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Intelligence Handbook

Technical Notes on Petroleum Industry Operations
A Compilation of Articles from
International Oil Developments

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Preface

These articles have been presented in ***International Oil Developments*** during the past five months to briefly explain some technical aspects of petroleum industry operations. They are brought together in this publication as a service to readers who have expressed special interest in the subject.

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Exploration

FINDING OIL AND GAS

Petroleum Exploration

Oilmen often say that oil is *where* you find it. What they mean is that, even with the best information available, one never knows with certainty where oil is before drilling. There is, however, general agreement that the better the information, the better the chances for success. Supplying this information is the job of the oil geologist and geophysicist.

Subsurface rock conditions affecting petroleum's origin, migration, and accumulation in structures and traps fall within the province of geological science. Measurement of the size and other physical characteristics of underground petroleum formations falls within the province of geophysical science. The rapid advance of petroleum geophysics over the last decade has revolutionized the economics of petroleum exploration. Development of extremely sensitive measuring devices has greatly narrowed the range of uncertainty in dealing with offshore exploration areas, for example.

Oil and gas come from decayed organic material buried in sea water, sand, clay, silt, and lime deposits. Eventually, the organic material is transformed into petroleum by high pressures and temperatures. Because gas is lighter than oil and oil is lighter than water, petroleum tends to float and migrate through porous rocks to higher levels. Ultimately, the migrating petroleum either seeps out at the surface or accumulates below ground in structural and stratigraphic traps. Migration ceases when the petroleum encounters an impervious caprock that seals the underlying porous sandstone or limestone reservoirs. The world's largest oilfields are located in domal or anticlinal structures. The search for petroleum is essentially a quest for these and other structures.

Geophysical Surveying

Three basic tools are used by geophysicists to map subsurface structures – magnetometers, gravimeters, and seismographs. Each instrument provides an indirect method of exploring subsurface rock without drilling. Geophysical surveys fall into two broad categories: reconnaissance surveys to outline new areas and detailed surveys to locate well sites on a given structure. Airborne magnetometers and gravimeters can survey vast terrain and locate prospective petroleum areas at a reasonable cost. Sedimentary rock – the only rock that can contain oil or gas – is practically non-magnetic and less dense than basement (metamorphic and igneous) rocks. Continuous measurement of variations in the earth's magnetic and

gravitational forces from an airplane permits geophysicists to infer the thickness of overlying sedimentary rock structures. The magnetic and gravity data are then plotted on a map. Contours of the high values indicate basement structures and anticlines, while contours of the low values indicate depressions or synclines.

The most accurate and detailed subsurface mapping prior to drilling is obtained by taking seismograph readings along a grid pattern of shot lines. Weights are dropped or explosive charges detonated at specified points on the surface along each shot line to send shock waves into the earth. These shock waves are reflected back to the surface and received by a battery of geophones, which relay the signal to an instrument recording truck. The time between emission and reception of the reflected signal rarely exceeds six seconds and is measured to one-thousandth of a second. This travel-time data is recorded on magnetic tape in digital form and processed by a computer. Once the velocities are calculated, the geophysicist can estimate the depth of various reflecting rock layers and determine the presence or lack of structures and traps. However, seismic surveying usually is limited to the mapping of subsurface rock layers that are more than 50 feet thick. Costs vary from $250 per linear mile offshore to $3,500 per mile onshore in swamps in southern Louisiana.

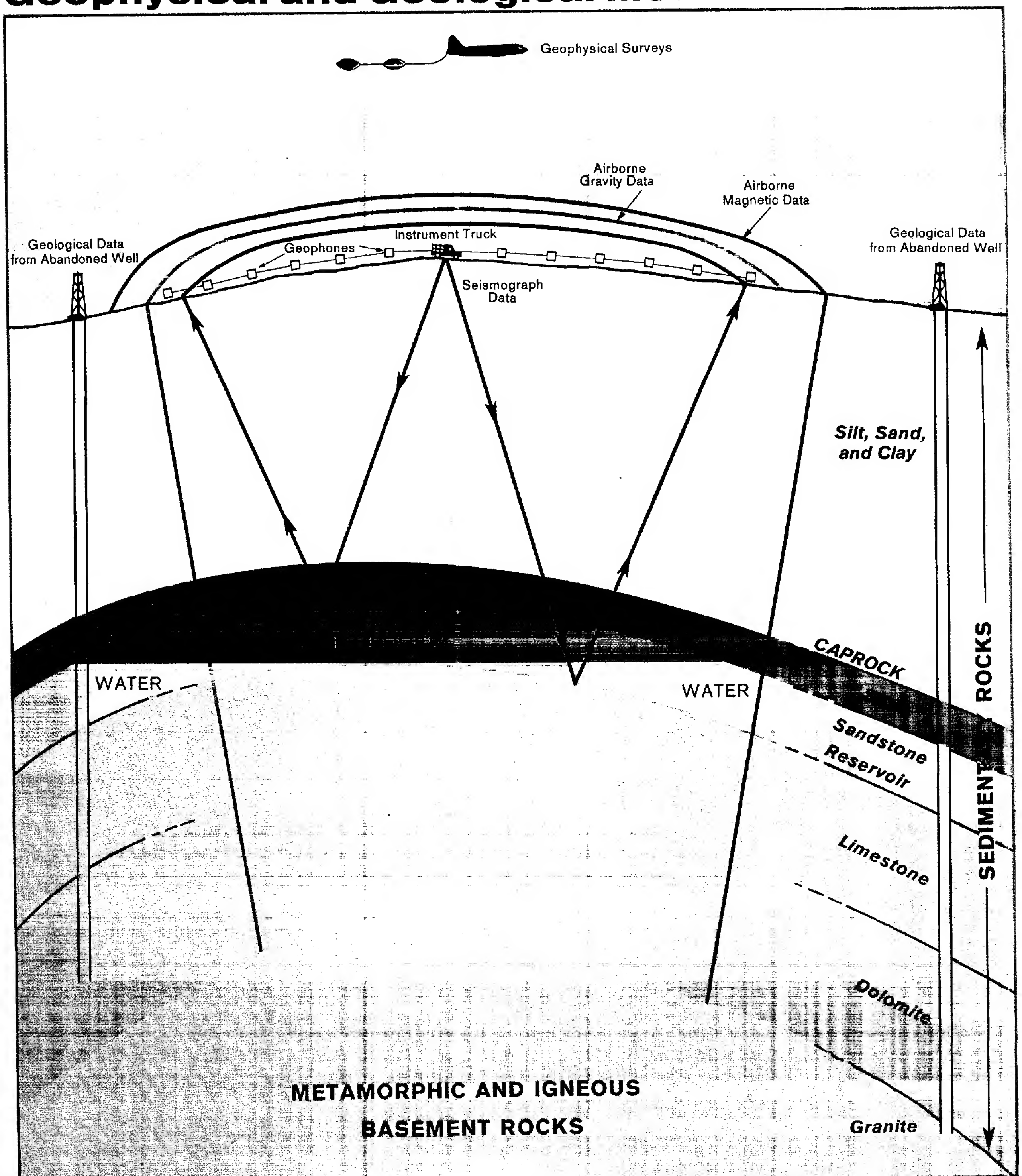
Geological Surveys

Geological surveys involve the mapping and analysis of surface and subsurface rock formations. The geologist examines rock samples taken from surface outcrops and wellbores of wells previously drilled in an area. He may be able to trace producing strata across a basin and examine their surface outcrops near the basin's perimeter. Cores, or plug-shaped samples retrieved from the wellbore, and rock cuttings from the drill bit may reveal traces of hydrocarbons or other information. Electric logs taken from key wells after drilling provide a more complete picture of the rock column. Evaluation of the rock samples and electric logs from all wells in the adjacent area enables the geologist to extrapolate subsurface data into adjacent undrilled areas. Changes in rock thickness, composition, and depth of strata often suggest the presence of structures and traps suitable for drilling.

Correlation

Before drilling begins, all geophysical and geological data for the site are compared by the exploration staff of the petroleum company. If the geological cross-section of the prospect presented by the geologists is confirmed by the geophysical data, authorization for drilling normally is granted. If the geological and geophysical data conflict, the staff rechecks the data for errors and gaps. If warranted by the data, exploratory drilling is authorized. The resulting subsurface information may give leads that permit the discovery of new oil and gas pools.

Petroleum Exploration: Geophysical and Geological Methods



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OIL AND GAS RESERVOIRS

Reservoir Characteristics

Oil and gas are formed from decayed organic matter that has been buried and compacted under intense pressure and heat for long periods of time. Since oil and gas are lighter than water, these hydrocarbons float on the underground water table and are driven upward by water pressure through porous rock until trapped, sometime in vast quantities, in a natural reservoir. These reservoirs have three essential properties which permit accumulation of oil and gas:

(1) A porous, permeable formation to contain the oil, gas, and water.

(2) An overlying impervious cap rock, which acts as a seal.

(3) Traps to prevent the lateral movement of the oil and gas. If the cap rock is dome shaped, forming its own sides, the reservoir is called an anticline. If the cap rock is a tilted layer, and the oil bearing rock beneath it is surrounded by impermeable rock, the reservoir is called a stratigraphic trap.

Most of the world's largest oil and gas fields are characterized by anticlinal, or dome-shaped, structures.

Recovery of Oil and Gas

Oil and gas accumulate in reservoirs in varying proportions. Recovery of the dominant hydrocarbon (e.g., oil) usually involves some output of the associated by-product (e.g., gas). When trapped, oil and gas are put under pressure by the force of the underlying ground water. If the reservoir is tapped by a well, oil and gas move through the porous reservoir rocks and flow up the well bore as long as the natural reservoir pressure exceeds that of the surrounding ground water. During the initial recovery period, reservoir pressure often is sufficient to force the oil and gas to the surface naturally.

With the gradual decline in reservoir pressure, some water will eventually surface with the oil, reducing the amount of oil extracted.

Reservoir pressure, along with the permeability and porosity of a producing formation and the viscosity of the oil, govern the rate of oil recovery. The maximum efficient rate of recovery (MER) is determined for each well and pool individually to optimize overall recovery and profits. Eventually, pumps must be used to lift oil to the surface and compressors installed to force low-pressure gas into field gathering lines. In areas remote from gas consuming markets, gas may be reinjected into the reservoir to repressure the oil pool. Where pressure is adequate or equipment is lacking, the gas may simply be flared.

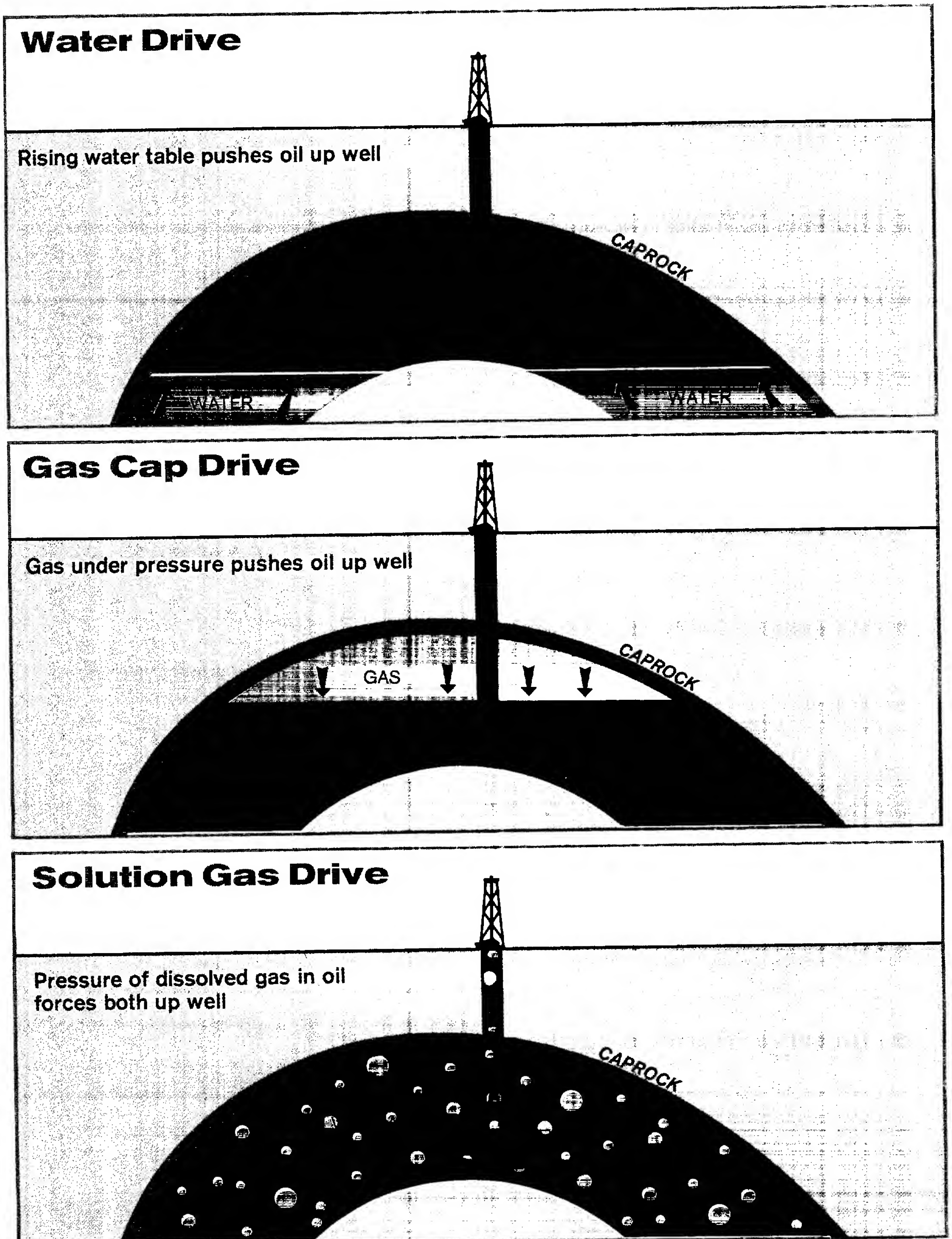
Most petroleum reservoirs are characterized by three types of natural production drive forces:

(1) water drive,

(2) gas cap drive, and

(3) solution gas (dissolved gas) drive

A combination of these drive forces may operate simultaneously in the same reservoir, although one is usually dominant. These drive forces are depicted graphically in the chart.



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EVALUATION OF NEW FIELD DISCOVERIES

New Discoveries of Oil

The discovery of oil in exploratory drilling does not always mean that a commercially viable oilfield has been found. Indeed, before recent crude price increases lowered the profitability threshold, only about one discovery in four was commercial. In addition to the price of crude oil at the time of the discovery, several other factors determine whether a new field will be considered worth exploiting. The most important of these factors are: the size of the reservoir, the thickness and characteristics of the formation, and the quality of the oil. Tentative judgments must be made on the basis of information derived from the first well. Misjudgments can result either in abandoning a potentially profitable field or in wasteful drilling of additional expensive wells.

The flow rate of the exploratory well – now often determined by a drill stem test -- is an important early indicator of reservoir potential. Several discoveries of 100,000 b/d or more have been reported in the past, such as Gach Saran in Iran and at Spindletop, near Beaumont, Texas. A 50,000 b/d flow test suggests a very large reservoir. Flow rates of between 500 b/d and 10,000 b/d are much more common and usually indicate commercial finds. Flow rates well below 500 b/d may be commercial if the quality of the oil is high, the formations are shallow, or the new field is located near existing fields with transportation and other facilities.

Drill Stem Tests of Exploratory Wells

The best measure of a potential new reservoir's productive capacity is the drill stem test. A cylindrical tool with ports and valves is attached to the drill pipe and lowered through the drilling column to the bottom of the well. A rubber packer at the top of the tool, resembling a tire around the drill pipe, expands when the drill pipe rests on bottom, sealing off the section to be tested. When the valves of the tool are opened, gas, oil, and water enter the drill pipe, usually in that order. A diagram of a drill stem test follows.

If reservoir pressures are moderate, only a portion of the drill pipe is filled. If the reservoir pressure is high, the drill pipe may fill to the surface, and spill oil and water from flow lines into excavated earth pits or, in the case of offshore drilling, into reserve storage tanks. Large gas flows usually are flared into the air for safety reasons. Offshore platforms rarely can store more than 3,600 barrels of fluid, and excess petroleum recoveries must be atomized and flared off with special burners. After one to six hours, the test tool is raised to the surface. Throughout the test period, recording devices at the bottom of the tool measure the reservoir pressure.

Confirmation Wells and Field Evaluation

Petroleum geologists' original estimates of subsurface conditions are confirmed, rejected, or revised on the basis of the data obtained from the discovery well. Analysis of geophysical logs of the wellbore, samples of fluid and rock, and prior seismic data provide a more complete picture of subsurface conditions. To estimate ultimate total oil and gas recovery from the reservoir, it is necessary to drill a series of confirmation wells. The number of confirmation wells required for complete evaluation of a field varies from several to a couple of dozen.

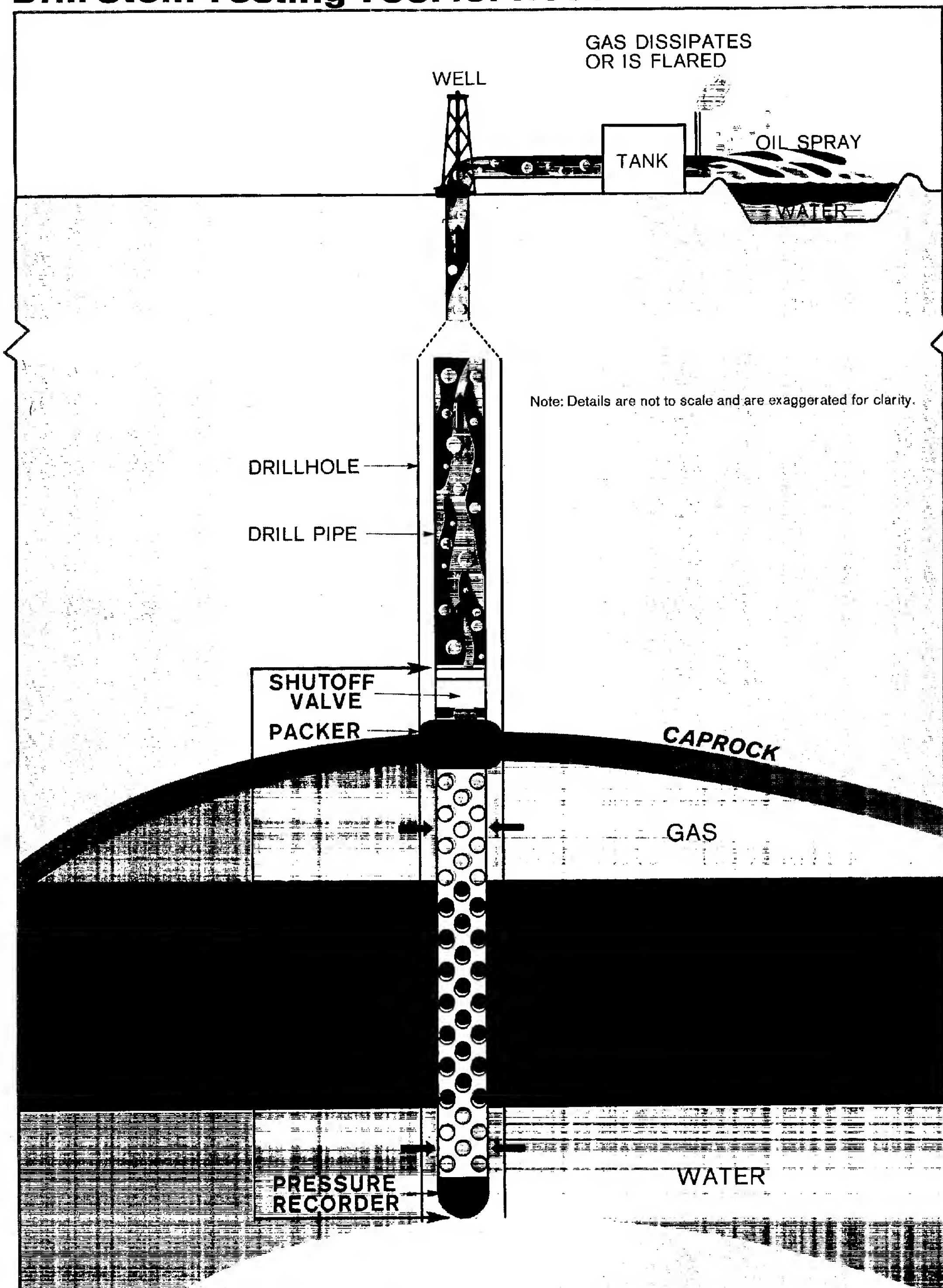
Plans for the initial confirmation wells are based on immediate needs for more specific geological and reservoir data. The size and shape of the petroleum-bearing strata and the position of the gas-oil-water contacts can be verified only by drilling. In some wells, cores (plug-shaped rock samples) need to be taken from the petroleum-bearing sections of the wellbore so that porosity, permeability, and oil and water saturation can be determined by laboratory tests. Also, samples of oil and gas must be taken from all prospective reservoirs for laboratory analysis. Identification of the chemical and physical properties of the petroleum samples often determines the choice of production and treatment methods and allows early ordering of specialized equipment and services.

Locating the Confirmation Wells

The locations of the initial confirmation wellsites are based on the best geological and seismic data available at the time. If, for example, the initial discovery well is located on the crest of a typical elongated dome-shaped structure, two rows of confirmation well are drilled -- one row along the crest and another bisecting the first at a right angle. Drilling of evaluation wells usually proceeds in all four directions at specified intervals until the pool edges are located. The distance between evaluation wells normally is governed by the presumed size of the structure and the thickness of the reservoirs. On very large structures with thick reservoirs, confirmation wells may be sited from one to several miles apart. On small structures with thin reservoirs, the wells are spaced closer and are called stepouts if less than one mile apart. Evaluation drilling programs are kept flexible so that one well's results can determine the next well's location.

As drilling proceeds down the flank of the structure, intermediate wells may be required to locate precisely the gas-oil and oil-water contacts. These points are critical in determining the limits of the producing layers and in the calculation of oil or gas reserves. When reserves in commercial quantities have been proved, development drilling for production is initiated while delineation drilling continues.

Drill Stem Testing Tool for Reservoir Evaluation



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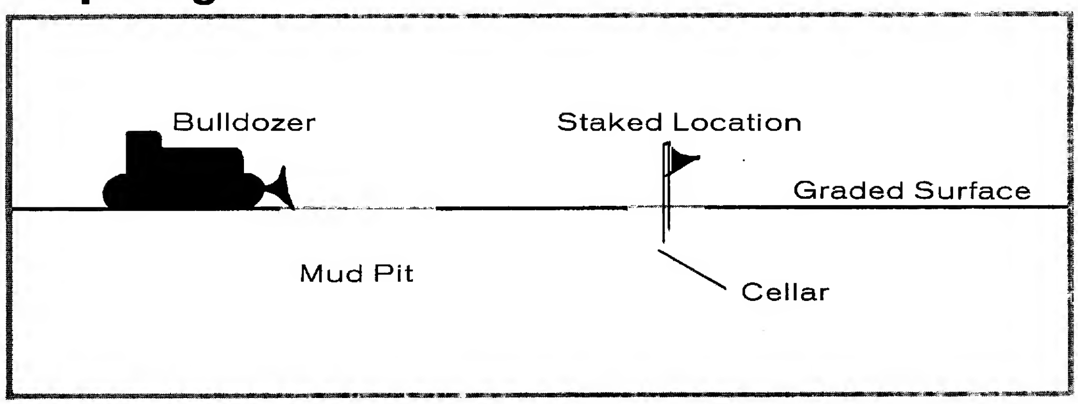
DRILLING A 15,000-FOOT WILDCAT

Preparing Location

After exploratory geophysical and geological studies indicate that a new area is worth drilling, the oil company acquires leases over the prospect and hires a drilling contractor. The best drill site is selected on the basis of subsurface geological data and its surface location is staked by a surveyor. A bulldozer levels the drill site and excavates pits for drilling fluids and sludge disposal. Usually a small cellar is dug around the surveyor's flag for the future installation of blowout prevention equipment.

Preparing Location



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Drilling Tools and Methods

The most widely used drilling technique in the Free World is rotary drilling, although cable tools, turbodrills, and dynadrills also are used in certain areas and for specific tasks. In rotary drilling the entire drill column and bit are rotated from the surface by a chain-driven rotary table. High-quality steel drillpipe and drill collars are required to withstand the torque, and durable bits are essential to withstand high axial loads in deep drilling.

Cable tools are suitable only for very shallow wells, while turbodrills and dynadrills are used mainly for "sidetracking" or the directional drilling of slanted wells. Both turbodrills and dynadrills employ downhole motors powered by drilling fluid that rotate the bit while the drillpipe remains stationary. In the USSR and Eastern Europe, normal drilling is also done with turbodrills, so lower grades of drillpipe can be used.

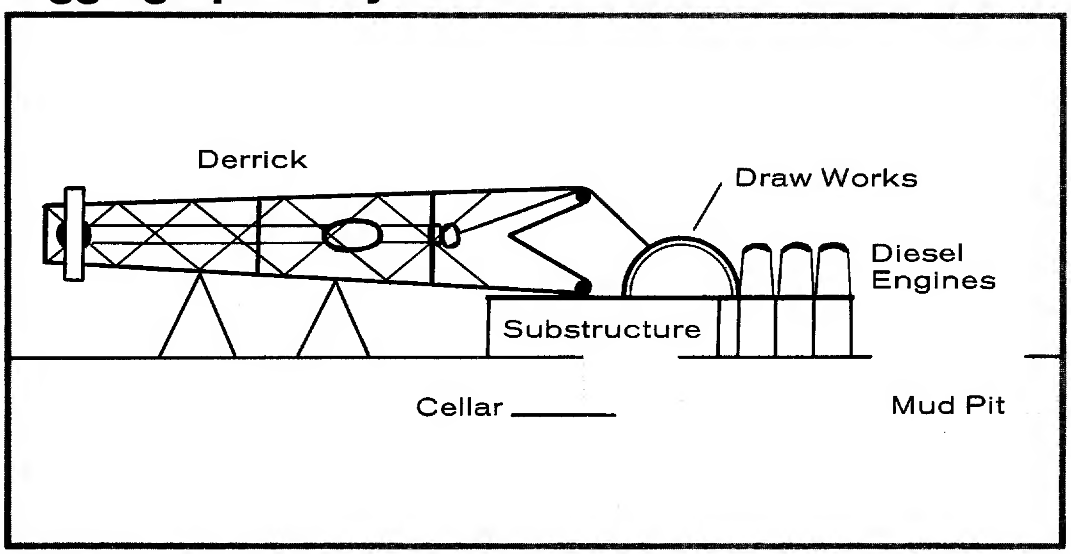
Moving in and Rigging Up Rotary Tools

Rotary rigs can be moved by truck, helicopter, or barge. The mast, or derrick, usually "jackknifes " or "telescopes" so that it can be raised and lowered quickly. Large masts break down into two or three sections when moving. The rig substructure, powerplants, mud pumps, and pipe platforms also divide into compact units that permit rapid movement and reassembly.

The substructure is centered over the newly staked location and cellar and is aligned properly with the mud pits. The mast is reassembled on the ground in a horizontal position while two legs are hinged to the derrick floor, on top of the substructure. Once the powerplant and the drawworks are installed, the mast can be raised to the vertical drilling position. The mud tanks and other ancillary equipment are then moved into position and connected.

An important last-minute task is to check out the drawworks and drilling line between the crown block and traveling block. This block and tackle arrangement raises and lowers the swivel hook and drillpipe during drilling operations. The brakedrum of the drawworks also must be inspected. If either the brake or the cable fails, the entire drill string could be lost in the hole and the traveling block could fall on the crew members working on the derrick floor.

Rigging Up Rotary Tools



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Spudding the Well

Once the rig is ready to drill, a large bit or "hole opener" is placed at the lower end of the "Kelly joint." The Kelly is a square joint of pipe 45 feet long which hangs from the swivel hook above the derrick floor, and it is raised and lowered through the square slot of the rotary table. The Kelly is always the

uppermost joint of the drill string. As the rotary table turns, the Kelly rotates the entire drilling column and bit below.

A 24-inch diameter bit may be used to "spud" a 15,000-foot-deep well. Drilling fluid or "mud" is pumped continuously down the Kelly and out through jets at the bottom of the bit. This fluid flushes the rock cuttings up the hole to the surface and also lubricates the drillpipe and the bit. Drilling fluid technology is complex. Many additives and fluids are mixed in specific proportions to remove cuttings and to coat the wellbore surface to prevent the sloughing of rock chips and pebbles into the hole.

As the well deepens, the Kelly sinks down the hole with the bit. After 45 feet of hole has been drilled, the Kelly is raised and the bit is removed. The first 30-foot drill collar is added between the Kelly and the bit. The drill column is reassembled and lowered back into the well and drilling is resumed.

Each drill collar may be 7 inches in diameter and weigh about 110 pounds per foot. As drilling progresses more drill collars are added directly below the Kelly to add weight and stiffness to the drill string. At a depth of about 500 feet, drilling ceases and a large-diameter conductor pipe is sunk to case-off the hole from top to bottom. Some 100 tons of rock cuttings from "spudding" a typical 24-inch-diameter 500-foot-deep hole is flushed to the surface by drilling fluid and collected in the shale pits.

Setting Casing

Surface casing is set after all of the loose unconsolidated rock has been penetrated. A conductor pipe 18-5/8 inches in diameter is hung from the surface to about 10 to 15 feet from the well bottom.

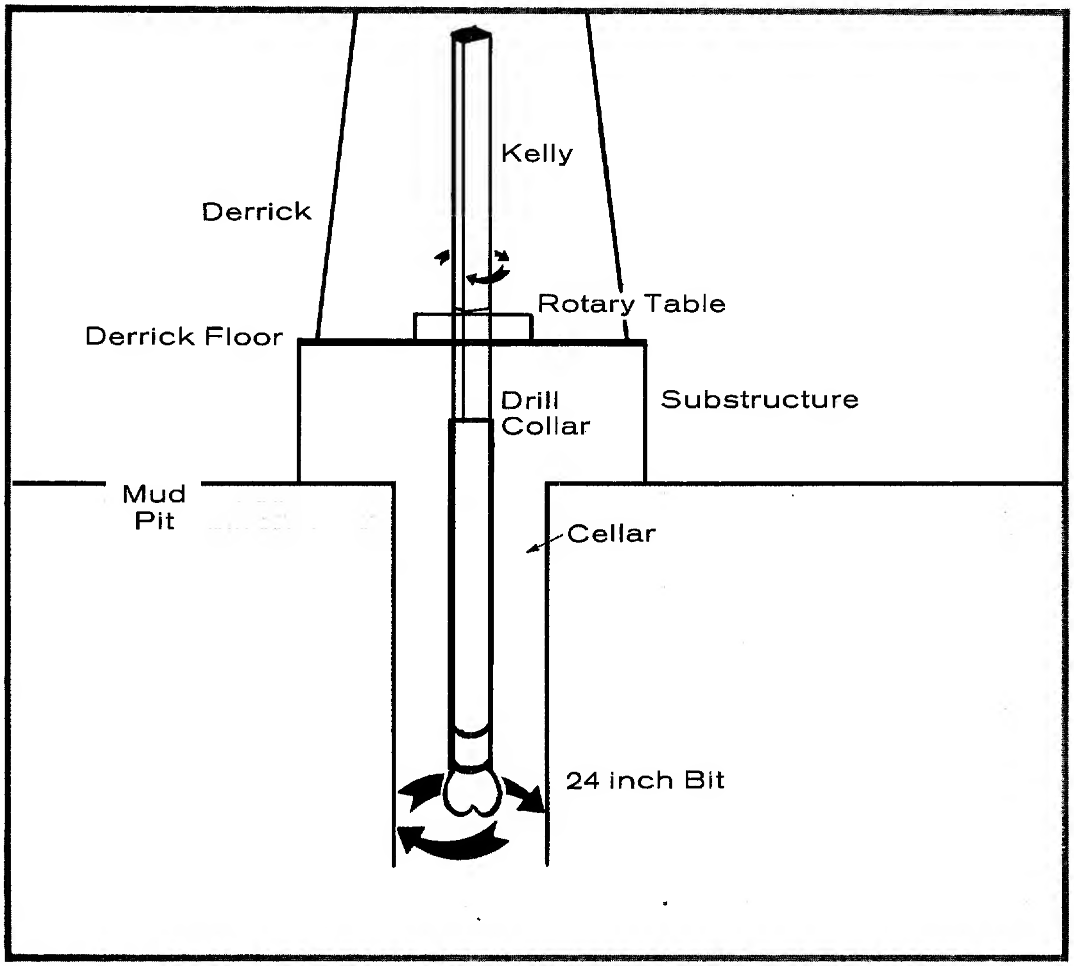
The casing is set with cement, which is pumped down through the casing ahead of a shoe chased by drilling mud. As the shoe, or plug, reaches bottom, the cement is forced up the annulus between the pipe and the wellbore, where it is allowed to cure and harden for several hours. Spudding and cementing 500 feet of surface casing can require two full days.

Drilling to Total Depth

After the surface casing is cemented in place, the blowout preventer stack is secured to the flange of the casing beneath the rig on the cellar floor.

Deep drilling is resumed using a smaller 17-1/2 inch bit which bores through the cement and continues beyond. At a depth of about 1,000 feet, the full complement of 20 to 30 drill collars will be in use. Faster penetration rates are now possible because the driller can place more weight on the bit safely. In soft rock, the well may be drilled almost as rapidly as the drill string can be lowered. Penetration rates of 300 feet per hour have been achieved in sandstone. In formations of dense hard rock like chert, the driller must watch a weight indicator

Spudding the Well



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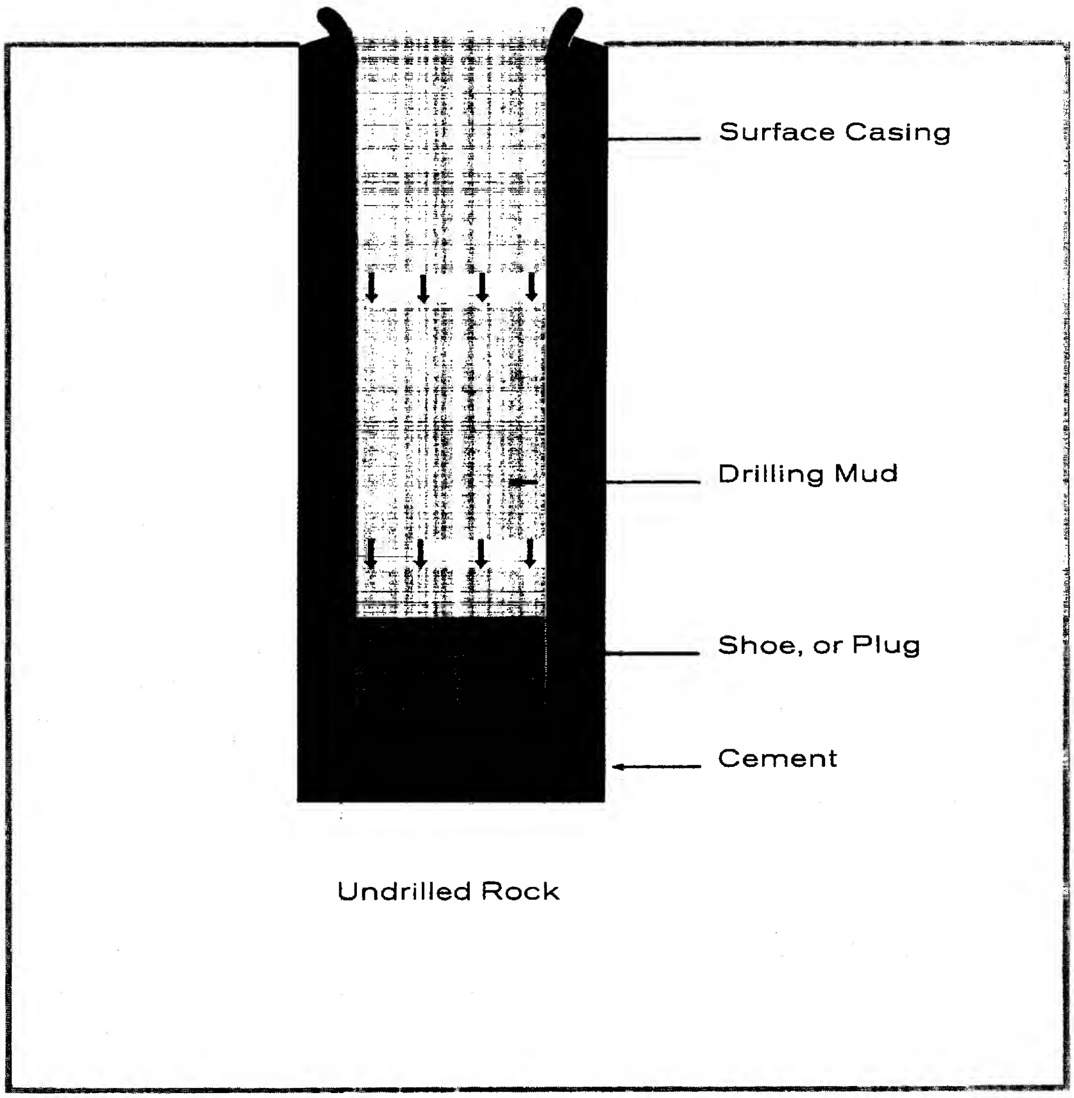
to maintain the maximum safe load on the bit. In such formations, penetration rates of 3 to 6 feet per hour may be the maximum attained.

The interaction of weight on the bit, bit revolutions per minute, and drilling fluid viscosity and composition determine drilling penetration rates in a given formation. Selection of the proper type of bit as well as normal bit life also affect drilling efficiency. When a bit wears out, the entire drill string must be raised to the surface and uncoupled in sections. The stands of pipe are racked upright in the derrick in "doubles" (two joints), "thribles" (three joints), or "fourbles" (four joints), depending on the height of the mast. The old bit is replaced and the drill string is reassembled and lowered back into the hole. The complete out-and-in procedure is called "tripping for bit." A "round trip" from 10,000 feet may take eight hours. New and better bits -- such as the tricone journal bearing bits with tungsten carbide teeth for hard rock and diamond bits for soft rock -- permit more than 400 hours of continuous drilling between trips, compared with 16-20 hours five years ago.

Setting Casing



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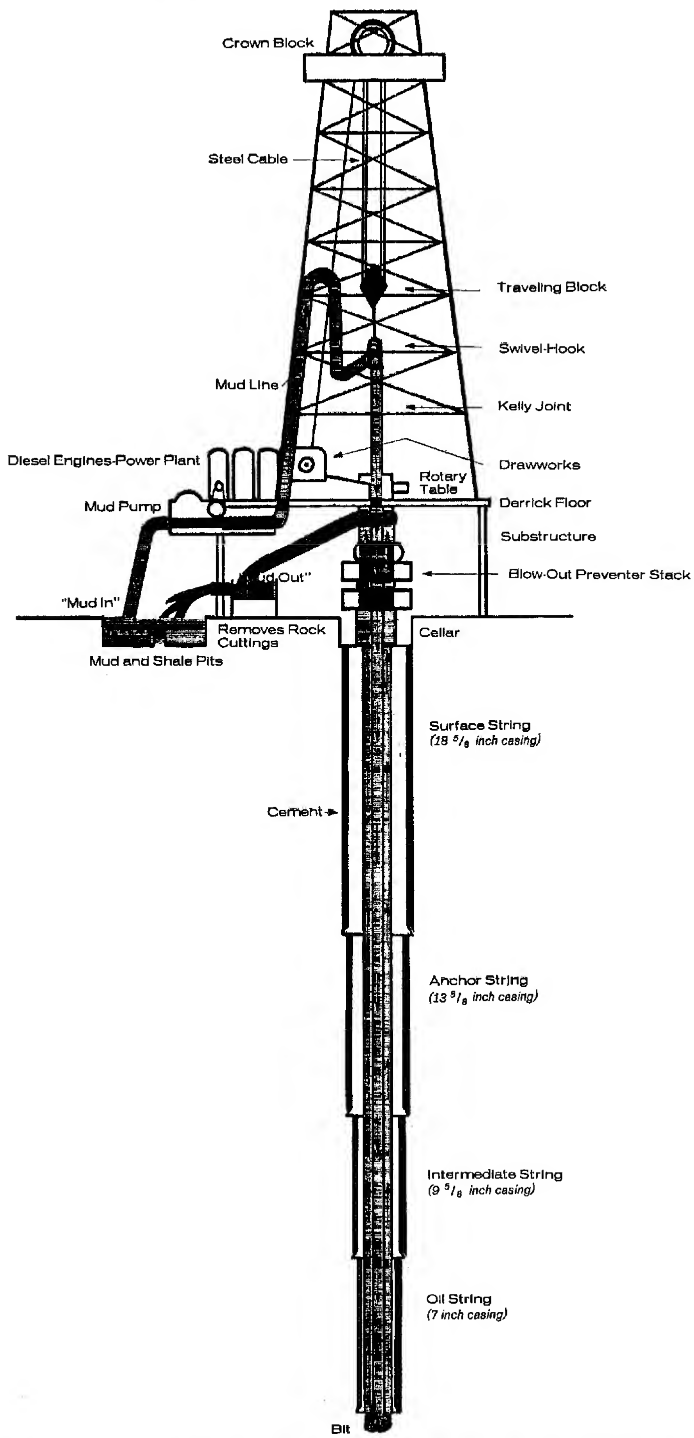
Drilling operations may continue to depths of 3,000-5,000 feet, when another "anchor string" of 13-5/8-inch casing is cemented, and to depths of 8,000 to 10,000 feet, when an "intermediate string" of 9-5/8-inch casing is set. If oil is discovered, an "oil string" of 7-inch casing may be run to a total depth of 12,000-15,000 feet. As each string of casing is cemented in place, further drilling requires the use of a smaller bit.

Drilling Breaks

The driller always observes the Kelly's rate of descent through the slot of the rotary table. Painted stripes or chalk tick marks enable him to determine normal penetration rates. If the rate doubles, he assumes that the "drilling break" indicates the penetration of a porous zone. After a few feet of penetration, all weight is removed from the bit while drilling fluid continues to be circulated to flush the

Drilling to Total Depth



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rock cuttings to the surface. The last few feet of rock cuttings are examined by the geologist for the presence of oil, gas, and water saturation. If the samples fluoresce under an ultra-violet light, the presence of hydrocarbons is established. A drill stem test is then taken to make a more definitive evaluation of the reservoir potential.

Lost Circulation

Experienced drillers also observe the drilling fluid level in the mud pits or tanks. If the fluid level drops unexpectedly during a "drilling break," it indicates that the drilling fluid is being lost and pumped into the porous strata just penetrated. Countermeasures must be taken immediately to raise the viscosity of the mud with additives. If the loss of circulation continues, bulkier materials such as cottonseed hulls, walnut shells, sawdust, wood chips, or other sealing materials may be pumped down the hole to close off the porous zone. Failure to curb the loss of drilling fluid can result in stuck drill pipe and loss of the hole and tools.

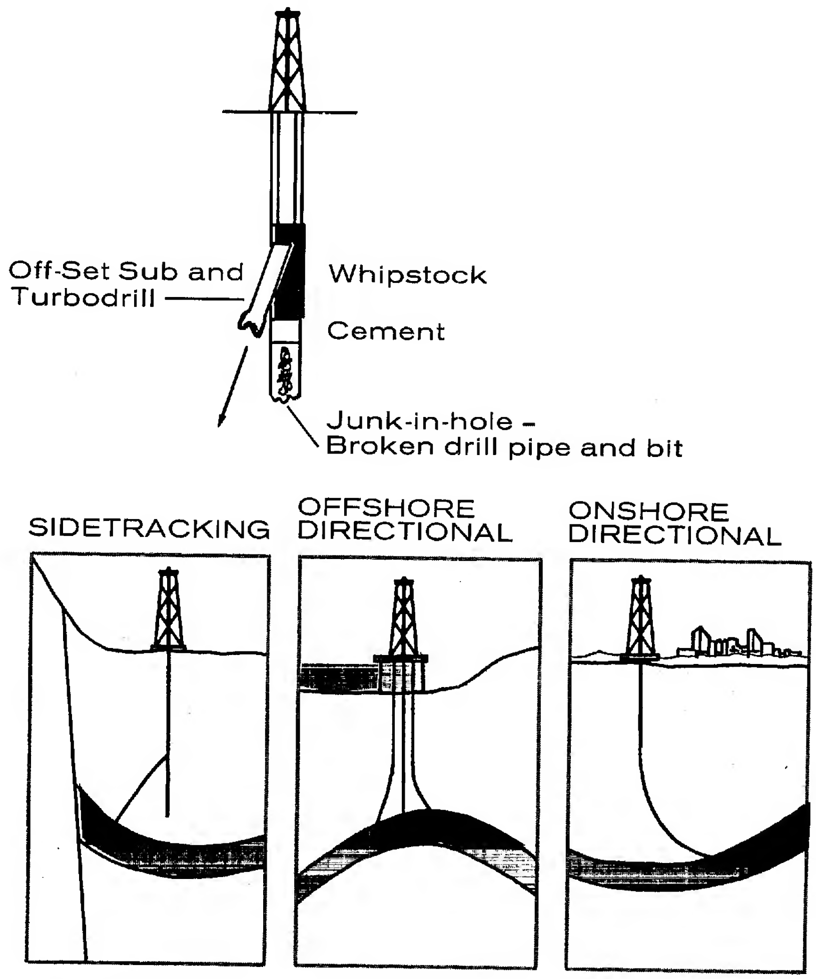
"Gas and Oil Kicks"

Sometimes a "drilling break" is encountered and the driller decides to bore through the entire porous zone before stopping to test for potential hydrocarbons. If oil and gas are present in the rock cuttings, it will not be known until the returns from the well bottom arrive at the surface for the geologist to examine. In the meantime, the driller watches the drilling fluid level in the mud tanks or pits for a surge, or buildup. If gas or oil are present and they start to flow, the fluid level will rise. If the fluid surges beyond a specified point, an alarm is set off, indicating a gas or oil kick. The driller then closes the upper blowout preventers and tries to kill the flow with heavier mud. If the well pressures build up to the point that the well could blow out of control, the blind-ram preventer is activated to shear the drillpipe and seal the well in.

Sidetracking and Directional Drilling

Occasionally tools or "junk" become lodged in the hole and, if they cannot be recovered by "fishing" operations, the well must be abandoned. In those cases where large sums of money have already been spent in drilling, salvaging a portion of the upper hole is possible by "sidetracking." Special tools permit the driller to deviate the wellbore and bypass the "junk" or obstruction. The hole is plugged with cement above the "junk." Either a whipstock or an offset sub and turbodrill are placed in the hole above the plug. The whipstock is a length of heavy pipe with a window on one side and tapered walls that cause the bit to veer off and drift laterally as it drills deeper. Turbodrills and dynadrills perform this task with little effort, since downhole motors have a natural tendency to drift and there is no torque on the drillpipe.

Sidetracking and Directional Drilling



for straightening or sidetracking a hole

for multi-hole drilling from one location, such as offshore installations

for reaching reserves under towns and cities

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In other instances, it is desirable to sink many widely separated wells from a single surface location such as an offshore production platform. "Directional drilling" of slanted wells to widespread bottom hole targets is accomplished the same way as in the "sidetracking" procedure.

DRILLING DISASTERS

Introduction

The drilling of oil and gas wells involves unique hazards, yet the incidence of disaster is surprisingly small. Of the 32,000 US wells drilled during 1973, probably less than 1% incurred substantial damage from accidents such as blowouts, fires, and oil spills.

Blowouts

The primary hazard is a blowout, which is defined as any uncontrolled flow of oil or gas from a well. A blowout can lead to an extremely dangerous and costly drilling disaster (Figure 1). Most blowouts occur during the penetration of petroleum reservoirs with unexpectedly high pressure. Others arise from equipment failures during maintenance operations at producing wells. Prior experience in an area normally alerts the crews to the existence of high-pressure strata and results in precautionary measures.

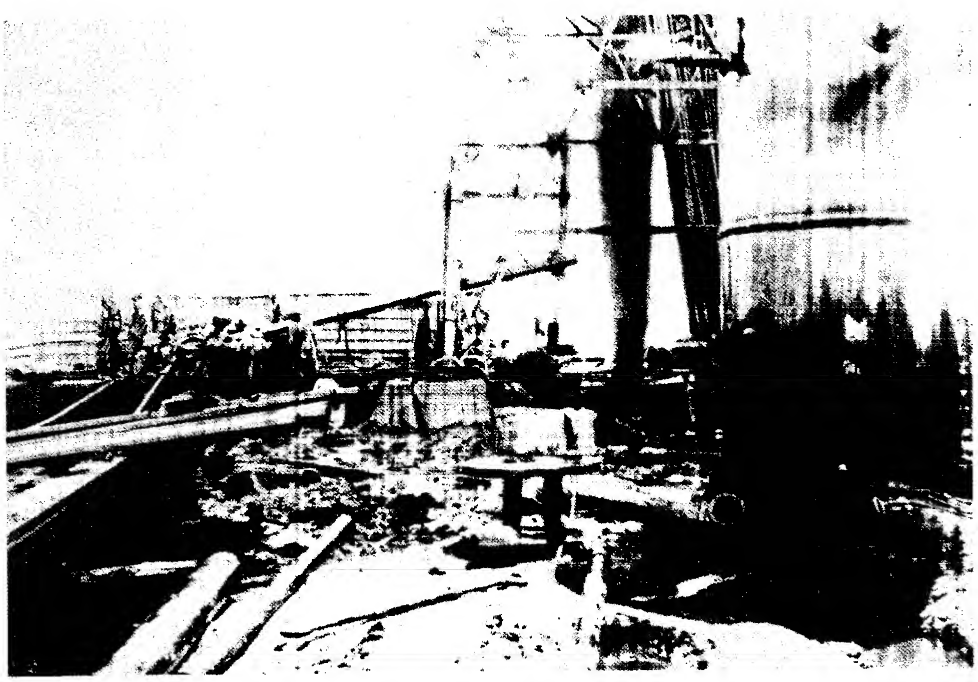


Figure 1. "WILD MARY," blowout at Oklahoma City, heralded the start of a new era in conservation and better completion practices. Today, gushers are a rarity and blowouts are dwindling in number.

If a drill bit unexpectedly penetrates a high-pressure reservoir or gas pocket, the driller may not be able to activate the blowout prevention system in time to shut the well in (Figure 2). Although normal maintenance and repair operations

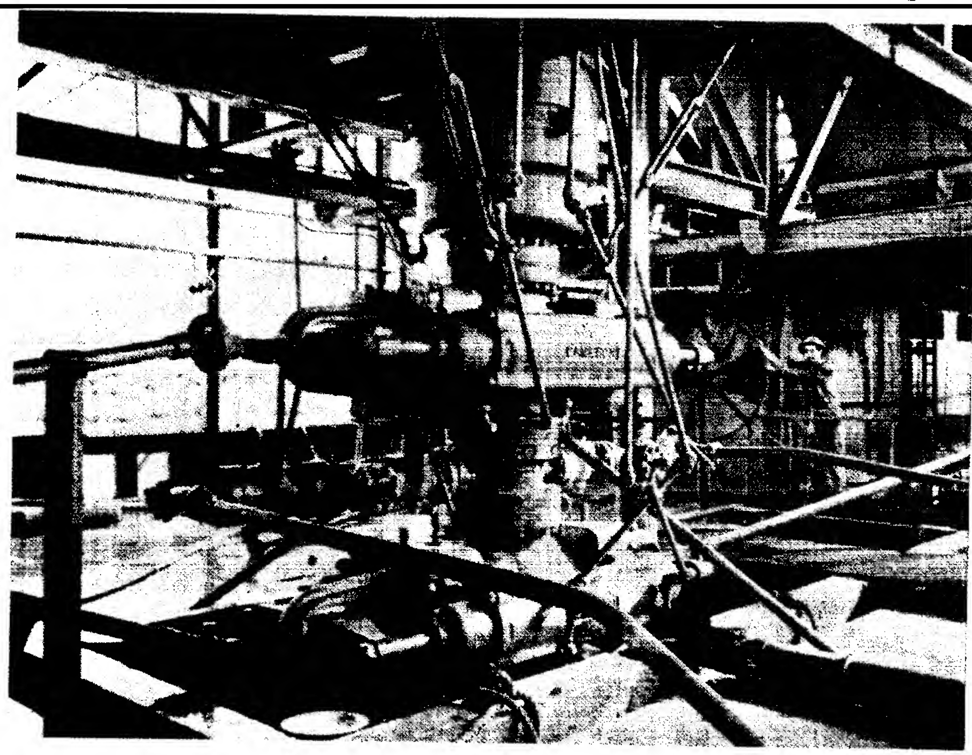


Figure 2. **BLOWOUT PREVENTERS,** properly designed and adequate for any kind of modern rotary drilling, provide safety.

are performed periodically on all high-pressure producing wells, shut-off controls and check valves sometimes malfunction as the critical zone is entered. In some cases where the flow of oil or gas cannot be stemmed, pressures are so strong that pipes, tools, and other equipment are ejected from the wellbore.

Drilling disasters resulting from oil and gas well blowouts fall into two categories. The first and most dangerous type involves high flows of oil and gas that eventually ignite and burn out of control. The second category involves blowouts that do not catch fire and hence are easier to cope with.

Oil and Gas Well Fires

A small oil and gas leak can build up to a spray and eventually become a gusher, a highly flammable mixture when vented into the atmosphere. Any spark from the ejected tools or fine rock chips striking the derrick framework can touch off an inferno. Sparks from electric switches and motors on the rig floor also can ignite the fumes. Well fires take a heavy toll in lives and equipment. Drilling rigs, production platforms, and other equipment can be destroyed or severely damaged if the fire is not extinguished quickly (Figure 3). If the fire is uncontrollable, the well and field also can be damaged. In World War II, the Ploesti

oilfields in Romania were bombed extensively, and the resulting well fires burned for several years before being extinguished by US specialists. During the interval, the fires went underground, damaging the producing strata.

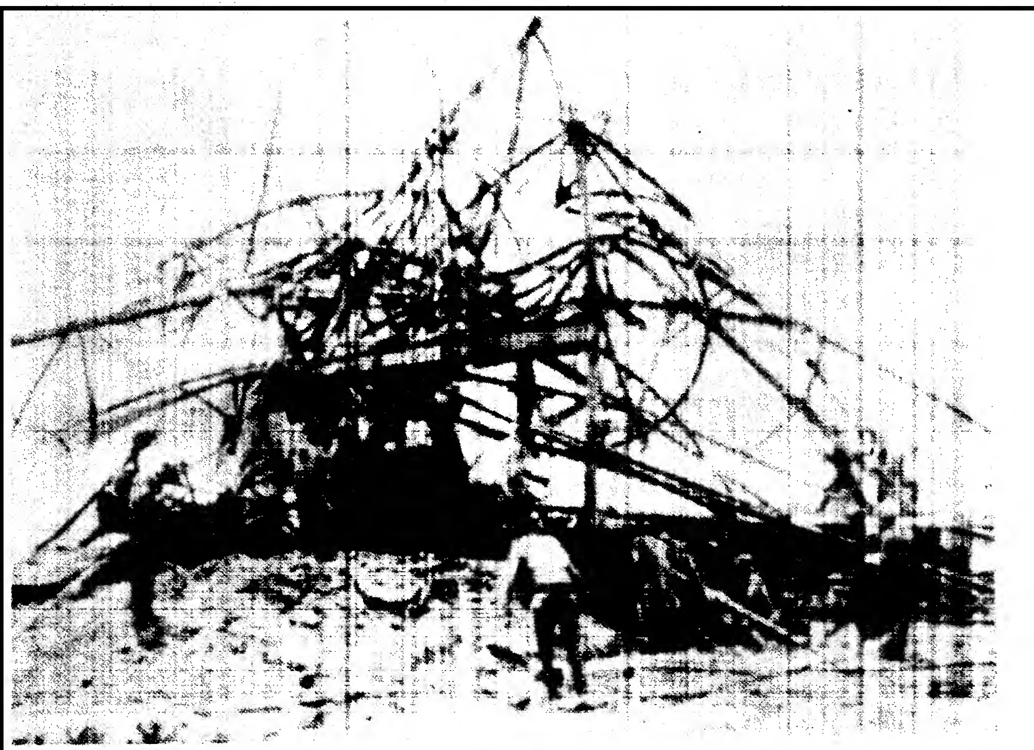


Figure 3. **BLOWOUTS ON ROTARY WELLS** occurred frequently in the early days. This rig was almost demolished.

Most well fires are extinguished by a combination of methods employed simultaneously. Firefighting specialists may spray the wellhead with foam retardants and water hoses to cut off oxygen and lower temperatures. Explosives are sometimes used to extinguish flames. Heavy drilling fluids are pumped into the well under great pressure to "kill" the well. Often it is necessary to drill several adjacent directional wells to intersect the burning well in order to inject enough heavy mud to "kill" the well.

Non-Burning Blowouts

Some wells blow out of control without catching fire. Unfortunately, non-combustible gases such as nitrogen can be just as destructive to men and equipment as oil and gas blowouts. Any high-pressure flow of oil or gases can carry fine sand and rock debris which is blasted loose from the wellbore surface. This abrasive material can sandblast above ground equipment and destroy the derrick after several days. Eventually, the legs are severed and the derrick collapses. If toxic pure methane or hydrogen sulfide escapes, people and livestock may have to be evacuated from the area, and local ravines and valleys may have to be publicly identified as dangerous areas.

Sometimes, after prolonged flows, the well site craters. Cratering is caused by the ejection of large volumes of sand and gravel that creates a subsurface void and surface subsidence (Figure 4). During the cratering process, other vents, cracks, and fissures can develop at the surface around the periphery of the well site. Most of the equipment settles into a large surface depression. Occasionally, the cratering process may extinguish the flow of oil or gas completely.

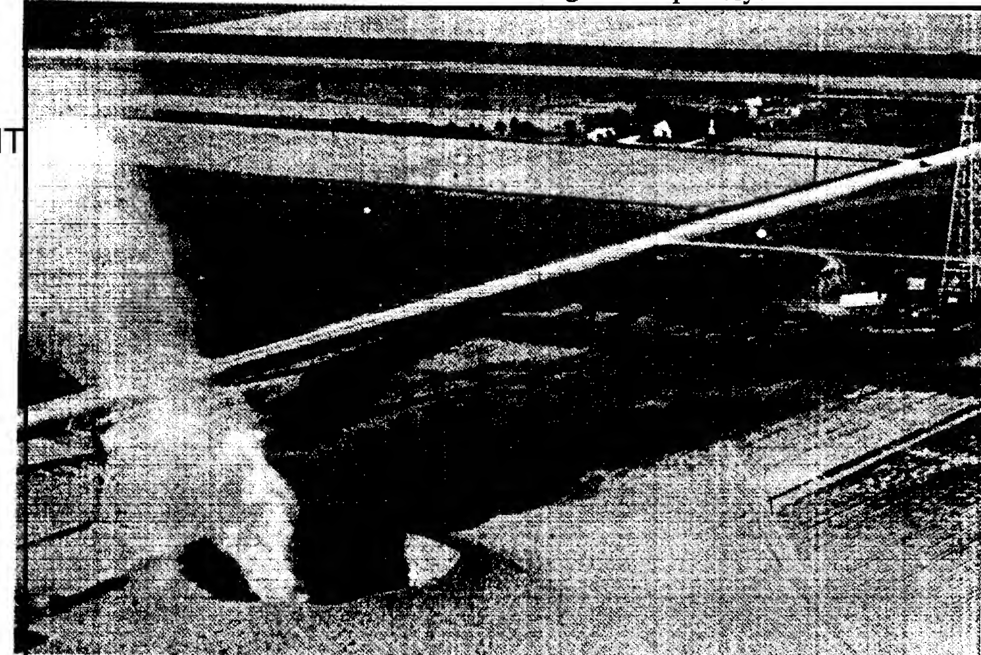


Figure 4. **MUD ENGINEERING** and improved drilling techniques have nearly eliminated this hazard. In this blowout, the gas well cratered and swallowed up the rig. Operator was forced to drill a directional well to kill the wild well.

In permafrost regions, the production of warm oil and gas streams at high velocities through uninsulated pipe or the use of unchilled drilling fluids during drilling operations are apt to cause ground thaw, pipe leaks, blowouts, fires, and surface cratering accompanied by peripheral ground fissures and venting (Figure 5).

Figure 5. Dramatic night shot of Panarctic's burning gas well on King Christian Island in the Canadian Arctic, showing both the 150-foot high flame from the well bore and a number of fissures in the ground, with gas escaping and burning 1,000 feet or more from the collapsed drilling rig.

Non-burning blowouts are capped in much the same way as well fires. In the absence of fire, it may be possible to emplace certain wellhead controls with cranes.

Oilwell Spills and Oil Seeps

Another type of drilling disaster occurs if uncontrolled oilflows and seepage cause damage to surrounding farmland, pollute the water, and upset the ecological balance of an area. Leaks in pipes or storage tanks caused by corrosion once were the source of frequent oil seepage. However, advances in technology and equipment have all but eliminated this kind of leak.

US firms have drilled more than 17,000 offshore wells since World War II, and fewer than 30 wells have experienced oil spills. Only four wells spilled more than 5,000 barrels of oil in offshore waters. However, large natural seepages are commonplace -- for example, in the Los Angeles Basin. Numerous seeps on the ocean floor can be observed from the air along the California coast between Santa Barbara and Goleta. Greater quantities of oil have escaped from these natural seeps than from the famous Santa Barbara oil spill of 1969. Early oil finders were attracted to this area because of these natural seeps. Subsequent development proved that this basin contained more oil per cubic foot of sediment than any other basin in the world. Ironically, the large number of oil reservoirs and seeps in the Los Angeles Basin owe their existence to the same natural phenomenon -- complex geological fault systems which not only trap oil but also allow it to escape.

THE COST OF OIL DRILLING AND PRODUCING EQUIPMENT

Some readers have asked about the cost of drilling an oil or gas well. There is no simple answer to this question. A shallow well drilled in, say, Pennsylvania obviously costs less than a deep well in the Amazon jungles or the North Sea. The cost of equipment, while only one factor in total drilling and completion costs, is fairly standard throughout the oil world and gives some idea of basic costs. These costs have soared in recent months as demand outraced supply.

Typical Deep Well Costs

Total costs vary between exploration and development wells and according to depth, well bore, testing, and logging expense. An example of costs for an 11,400-foot exploratory well drilled in the United States follows:

Key Equipment Items and Current Prices

Drilling Rigs and Platforms

*Rigs**

Complete with 2 drill strings for 7,000-foot depth: $1.0 million;

Complete with 2 drill strings for 10,000-foot depth: $1.5 million;

Complete with 2 drill strings for 15,000-foot depth: $2.5 million;

Complete with 2 drill strings for 30,000-foot depth: $4.0 million.

* Rigs for installation on large offshore drilling platforms carry three complete drill strings which can add $400,000 to the cost of a complete rig.

Offshore Exploratory Drilling Platforms

Costs range from $10 million apiece for 250-foot water depths, up to $45 million for 1,000-foot waters. About 114 platforms are on order worldwide, 22 of which are Norwegian Aker H-3 semisubmersibles specifically designed for North Sea service where 90-mile winds and 60-foot waves are prevalent. The Norwegians are emerging as the strongest competitors to US platform designers.

Offshore Development Drilling Platforms

Costs range from $2 million to $80 million, depending on type, the number of wells contained per unit, and water depths.

Drill Pipe and Drill Collars

These items are sold in 30-foot lengths; price varies with the quality of steel and weight and diameter of the pipe.

5-1/2" diameter grade E drill pipe: $11-$12 per foot

3-1/2" diameter grade E drill pipe: $8-$9 per foot

8" diameter drill collars sold in 30-foot lengths at 150 lb/ft: $1,500

4-3/4" diameter drill collars sold in 30-foot lengths at 50 lb/ft: $500

Rock Bits

Standard 8-5/8" diameter tri-cone (20-hour life): $300

Journal bearing 8-5/8" diameter tri-cone (400-hour life): $2,000

Diamond head 8-5/8" diameter (400-hour life): $4,000

Blow-Out Preventers (3 per rig in service)

10" internal diameter 5,000 PSI rated spherical type: $16,000

10" internal diameter 10,000 PSI rated spherical type: $25,000

10" internal diameter 5,000 PSI rated dual ram type: $20,000

10" internal diameter 10,000 PSI rated dual ram type: $40,000

Oilwell Casing

Casing is sold in 30-foot lengths, and prices vary according to quality of steel and diameter.

Standard 7" 20 lb/ft K-55 casing: $3.90 per foot

Standard 7" 17 lb/ft K-55 casing: $3.45 per foot

Standard 5-1/2" 14 lb/ft K-55 casing: $2.90 per foot

Oilwell Tubing

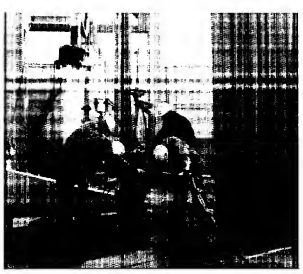
Tubing is sold in 30-foot lengths and prices vary slightly according to quality of steel and weight because only small diameters are used.

2-7/8" 6.4 lb/ft tubing: $2.50 per foot

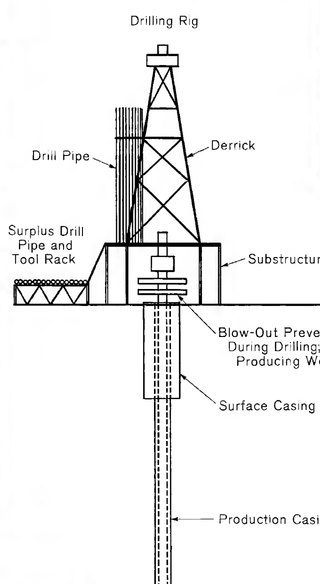
Well Heads (or Christmas Trees)

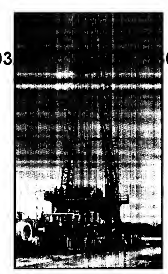
Unit costs vary and depend on size of fixture required, number of strings of tubing, and zones to be produced.

$5,000 to $15,000 each

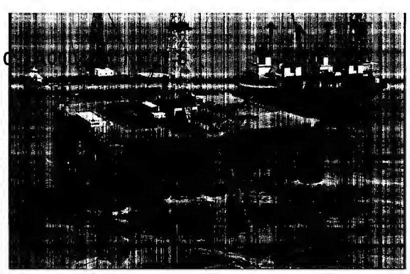


Drill Pipe

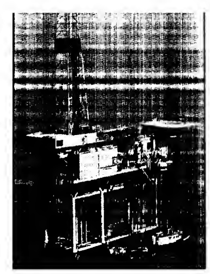




Onshore Drilling Rig

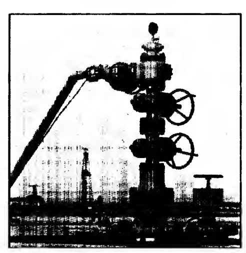


Offshore Exploratory Drilling Platforms

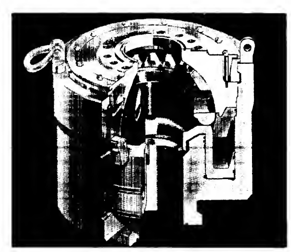


Offshore Production Platform

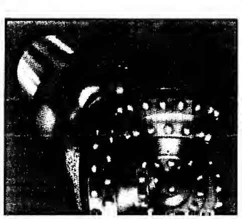
Drilling Tools

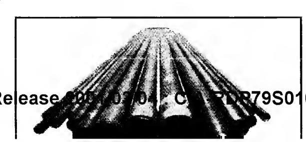


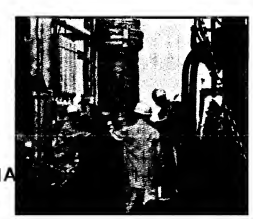
Well Head or Christmas Tree

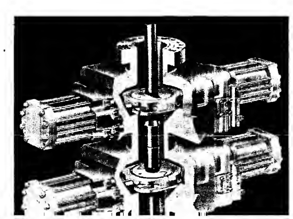


Spherical Blow-Out Preventer









PRODUCTION OF NATURAL GAS LIQUIDS

Confusion in Petroleum Statistics

Some measures of petroleum production and reserves refer only to crude oil; others include natural gas liquids as well, giving rise to apparently conflicting data. For example, US crude oil production amounted to almost 9.2 million b/d in 1973. Inclusion of natural gas liquids – butane, propane, and ethane recovered in liquid form -- raises the figure to 10.8 million b/d. Similarly, proved US oil reserves amount to 42 billion rather than 35 billion barrels if natural gas liquids are included.

What Are Natural Gas Liquids?

Natural gas and crude oil reservoirs often lie several thousand feet below the earth's surface. Reservoir temperatures increase at the rate of about 2° Fahrenheit with each 100 feet of depth and reservoir pressures at the rate of 1/2 pound per square inch per foot. Below 10,000 feet, some light hydrocarbons – butane, propane, and ethane – often accumulate in the form of natural gas liquids. The high temperatures separate them from crude oil and the high pressures keep them from becoming gas.

How Are They Produced?

When these reservoirs are tapped by a well, the flow of oil and gas to the surface may lower the reservoir pressure enough to permit the natural gas liquids to vaporize. When these vapors are collected at the well head, they begin to liquefy at the cooler temperatures in the collection pipes. Liquefaction is completed by compressors. Whether in their liquid or gaseous state, the natural gas liquids are referred to as "condensate" if originating from gas wells and as "associated" or "casinghead" gas if originating from oil wells. They are processed at field gas plants to produce the liquid petroleum gases (LPG) – butane, propane, and ethane – and a residue of the common natural gas, methane. LPG also is recovered in large volumes as a by-product of oil refining operations.

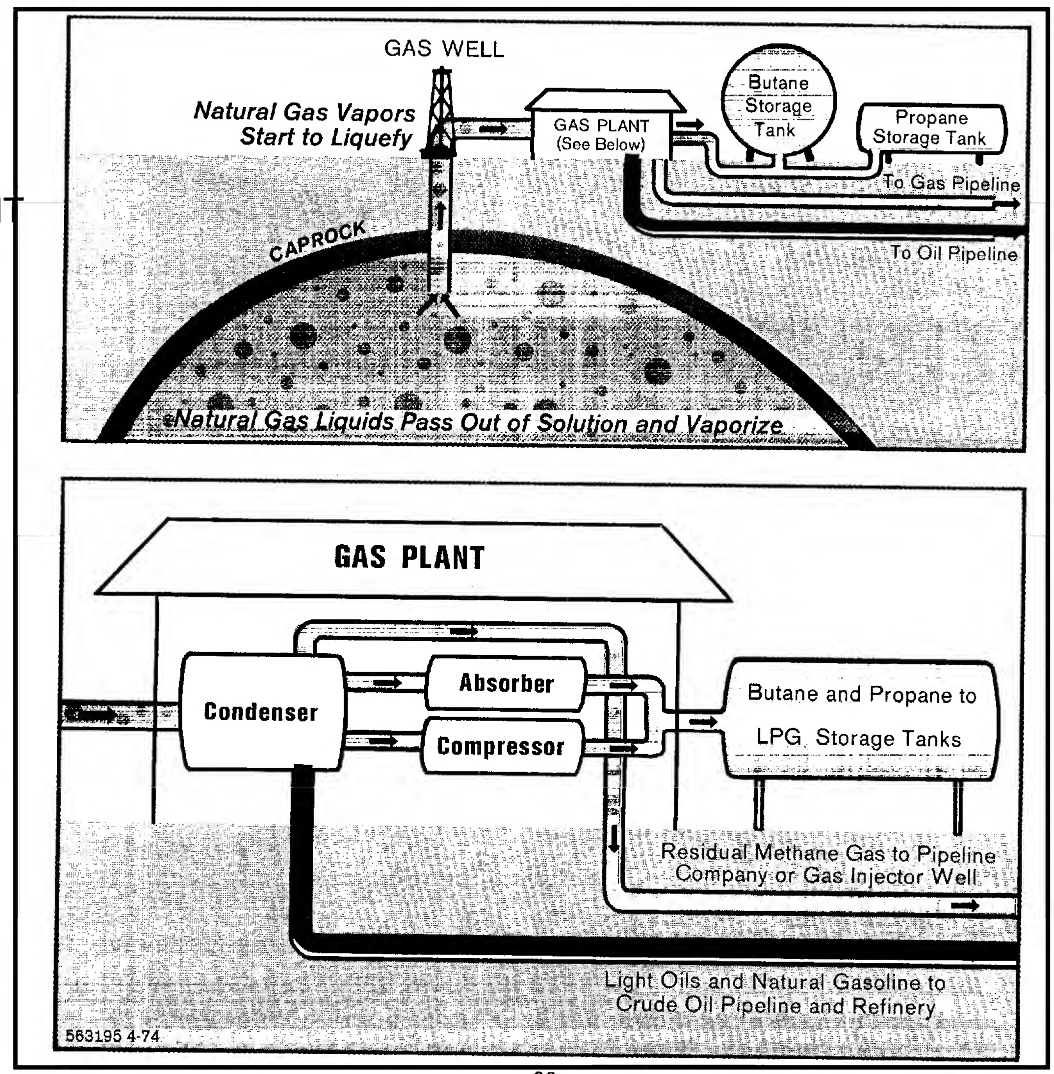
How Are They Used?

The United States is the largest producer of natural gas liquids; other countries such as Canada, Venezuela, Indonesia, and several Arab producing states also recover some of these liquids along with crude oil. Elsewhere in the world, the recovery of natural gas liquids at oil wells often is not feasible. In the absence of nearby markets, the liquids are sometimes mixed with crude oil or flared. If mixed with crude oil, the liquefied gases can render the oil unstable, making it difficult to transport, pump, and store.

In natural gas production, all liquids – whether recovered for use or not -- must be stripped from the gas at the surface prior to being piped. Failure to do so may result in the accumulation of volatile liquids in the low sections of the line, reduction of pipeline operating pressure, destruction of turbo-compressor blades, and irregular combustion as well as possible flash explosions in burners.

After processing, the natural gas liquids and the residue gas (methane) have a variety of uses. Methane, plus some ethane, is sold to natural gas pipeline companies for distribution and resale. Methane also may be re-injected to maintain pressure in the reservoir. Casinghead gas (natural gasoline) is blended with automobile gasoline refined from crude oil. Much of the butane and propane is distributed from large central storage tanks by tank trucks and dispensed locally in bottles or cylinders as a clean-burning fuel for rural or suburban homes. Butane and propane also are used as feedstocks for petrochemical production. Butane is used as a blending ingredient for winter-grade motor fuels because it ensures quick starting and hastens engine warmup.

The processing of natural gas liquids is illustrated in the accompanying chart.



SECONDARY AND TERTIARY RECOVERY OF CRUDE OIL

Secondary Recovery

There is a time in the life of an oilfield when the natural pressure of the reservoir is no longer adequate to force the oil out of the rock pores into the well bore. This depletion of the natural drive mechanism marks the end of the primary recovery phase. Prior to the 1950s, the operator of such a deposit had little choice but to abandon the field, long before the greater part of the oil had been recovered from the reservoir. It was not unusual for as much as 80% of the oil to be left in the ground. This obviously wasteful practice led to the development of repressuring methods to increase ultimate recovery.

Forcing oil out of reservoirs by means of a repressuring technique is termed secondary recovery. The simplest method is to inject water or gas to rejuvenate the original natural drive mechanism. Both of these displacement agents are cheaper than the oil being recovered. When water is used, the secondary recovery method is called "water drive" or "waterflooding." If gas is used, the process is called "gas drive" or "gasflooding." Water drive is the most often used secondary technique.

Water, gas, or both can be injected through a pattern of injection wells to drive the oil into nearby producing wells. An example of each process is illustrated below:

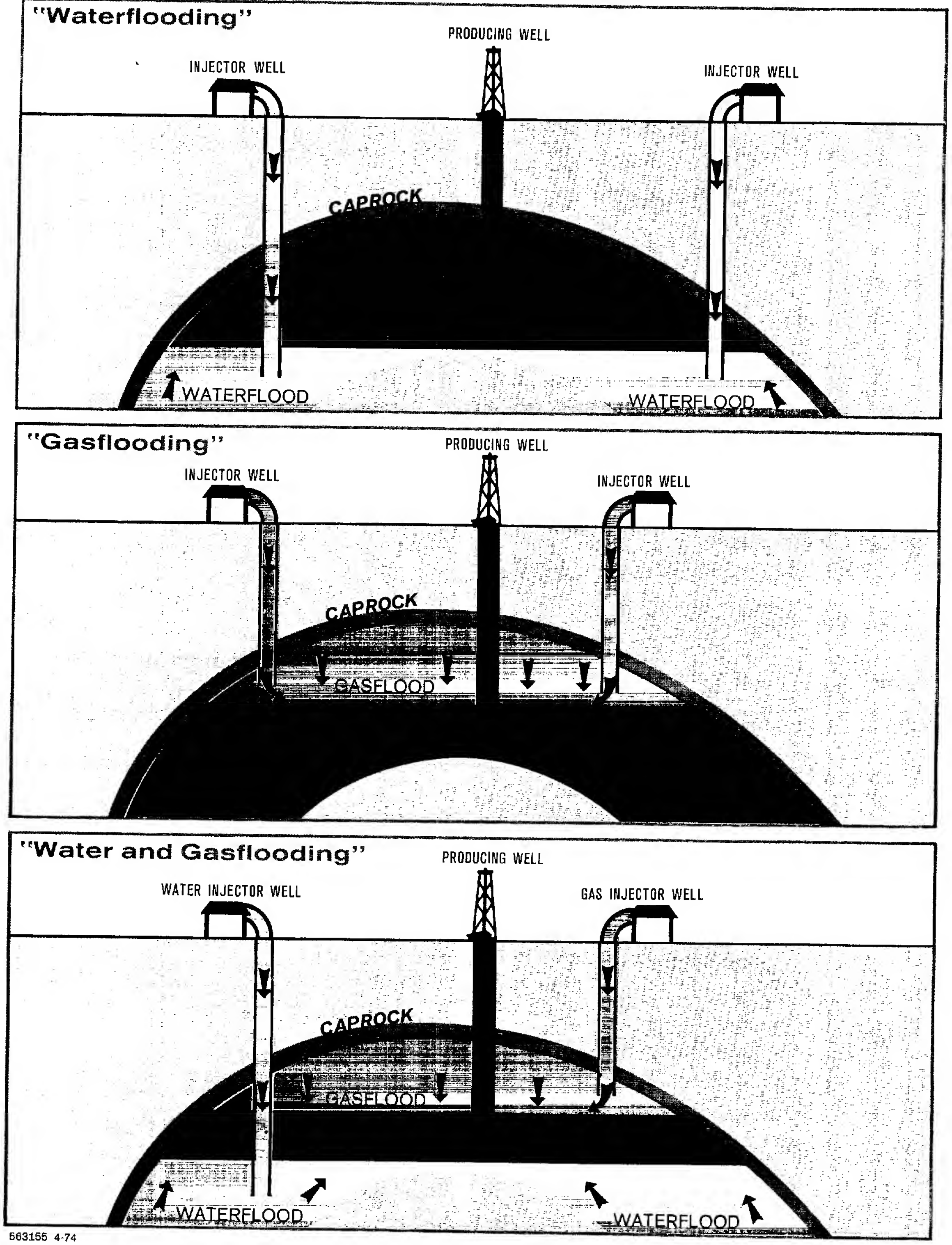
Waterflooding

The results of waterflooding may not become apparent until the amount of water injected into the field equals the amount of oil previously extracted. This may take as long as 1 or 2 years. Water forced into the producing rock layer must be free of suspended particles or chemical impurities that could block the pores in the reservoir. Any permeability loss would reduce the flow of oil to the well bore. The water must be injected beneath and at the edges of the oil pool to drive the oil upward and sideways into the producing well.

Gasflooding

Gas injection is usually through wells located at the top of the trap to force the oil downward and sideways into the producing well. Byproduct gas, which surfaces along with the oil, usually is recycled back into the producing strata to avoid the waste of flaring, if markets are not available.

Secondary Recovery Methods



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Pressure Maintenance

Shortly after water and gas repressuring techniques were developed, it was recognized that application of these methods early in the producing life of oilfields could avoid a reduction in natural reservoir pressures. Prolonged high rates of production and higher ultimate oil recoveries were thereby possible. When secondary recovery methods are applied early in the production stage, the technique is called pressure maintenance. At present, about 30% of the oil in place is recovered from most reservoirs by the use of both primary and secondary recovery methods. In the United States, secondary recovery projects add $0.35 to $1.50 to the cost of each barrel of oil produced by these methods. Approximately 33%, or some 3 million b/d of the oil produced in the United States, comes from secondary recovery and pressure maintenance operations.

Tertiary Recovery

Ultimate recovery rates of up to 60% of the oil in reservoirs are now judged technically feasible. Recently developed tertiary recovery methods, which involve complex chemical and thermal treatments of oil-producing rocks, greatly improve the efficiency of conventional water and gasflooding. Although such methods can double ultimate oil recoveries, they are costly. In addition to the secondary recovery costs of $0.35 to $1.50 per barrel, the use of chemical solvents and thermal recovery techniques could raise operating costs by at least another $0.75 to $1.50 per barrel or a total of $1.10-$3.00. Most tertiary recovery techniques are not fully proved and applications have been confined to pilot projects.

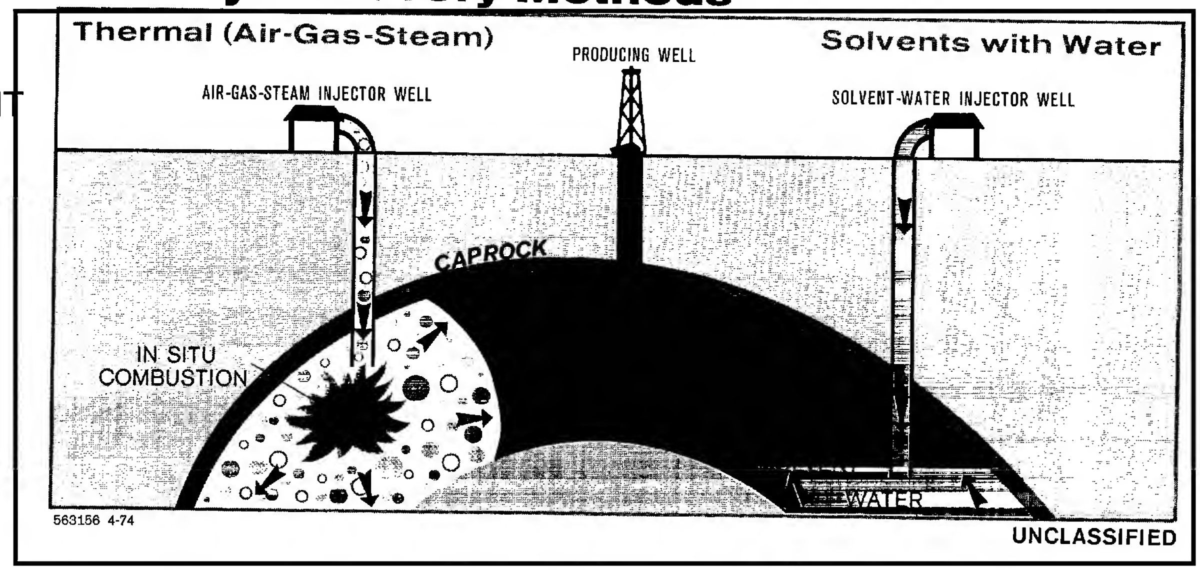
Chemical Solvents

Special chemicals are injected ahead of water to help flush the oil out of the reservoir rock and sweep it through the pores to the producing well. At present, these chemical solvents are manufactured in small quantities and are very expensive. If demand rises and solvent production is expanded, prices should decline. At current price levels, the profitable use of chemical solvents may depend on the ability of the operator to recover the solvent along with the oil.

Thermal Recovery

The extraction of heavy crude oil from reservoirs with very low ultimate recovery rates has been improved by the development of thermal techniques. When thick oil is heated by injected steam, hot water, or underground burning, the oil becomes thinner and begins to flow. In the burning process, which is called ***in-situ*** combustion, air injected to assist the underground combustion also becomes a displacing force.

Tertiary Recovery Methods



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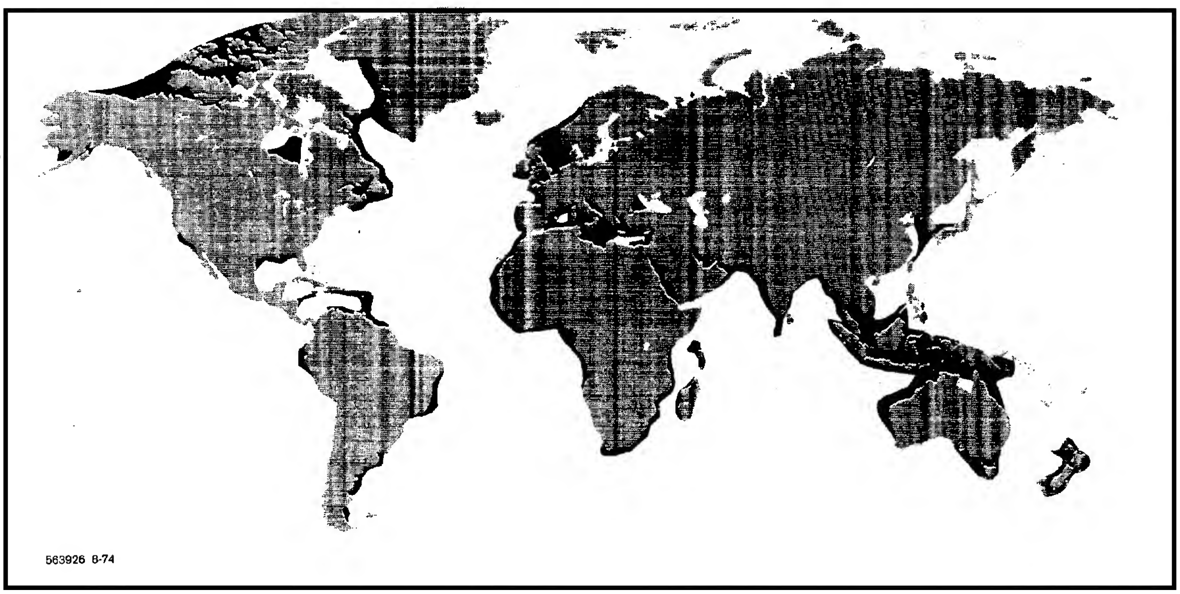
FUTURE SUBSEA OILWELL PRODUCTION METHODS

Introduction

The international oil industry has discovered about 176 billion barrels of crude oil and 248 trillion cubic feet of gas on the world's continental shelves since the first well was drilled out of sight of land 26 years ago. About 40 billion barrels of this offshore oil already has been produced. Offshore production exceeded 10 million b/d in late 1973, accounting for almost 18% of world output. Vast areas of the world's seabed, continental slopes, and shelves remain undrilled; and the offshore boom is just beginning. Most estimates indicate that offshore production will account for as much as half of total world output in 1985. Up to this point, the lifting of offshore oil has been through the use of steel platforms resting on the seabed. Future production methods, as described in this article, will entail the use of underwater wellheads.

Areas of Offshore Exploration and Production Activity



Present Status of Offshore Technology

The future for offshore oil production lies in ever deeper waters, where oil producers are certain new discoveries will be made. The improvement of existing platform technology will allow producers to work in waters beyond the 600-foot depth line -- normally the current limit of offshore production. Builders can readily employ many existing construction methods and designs to make larger and stronger platforms. Platforms have already been designed for operating wells in 700 feet

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of water off Santa Barbara, California. As improvements in equipment continue, most operators would probably be willing to drill in up to 1,000 feet of water where prospects are good. Shell has even begun drilling a well in about 2,150 feet of water 50 miles off the coast of Gabon. However, the techniques for completing and operating such wells from the surface remain to be developed.

Present methods of completing offshore wells in, say, 600 feet of water have focused on multiple platform complexes for purposes of convenience and safety. The main platform contains the wells, crew quarters, offices, and heliport. A second supports all production-handling equipment, such as pumps and flow lines. In some cases, a small third platform will support equipment requiring burners or heaters for oil and gas processing and treating operations (Figure 1). As the water depth increases from a few feet to 600 feet, costs mount exponentially. In an effort to limit costs, producers are turning to one all-purpose platform (Figure 2). Such a multideck platform must be suitably compartmented to support all necessary functions and still provide the safety of separate platforms.

Recently, a few companies have begun to develop new techniques and equipment that would transfer most of the functions of the platforms to undersea installations and would permit operations at depths beyond the technical limits of platform technology.

The Subsea Alternative

At least four companies, or groups, have been experimenting with seafloor oilwell completion techniques. The systems provide for manned "hands-on" operations. Operators will descend to the enclosed "dry" wellhead in diving bells and work in a "shirt sleeve" atmosphere. In contrast, "wet" wellheads conceivably will be employed in shallow installations and would be serviced manually by divers.

- Seal's Atmosphere System (SAS), developed by Mobil and North American Rockwell, uses "dry" subsea wellheads and a diving bell. Members of the Seal group have also developed a companion system for remote offshore sites (Figures 3 and 4).

- Lockheed, with Shell's help, has devised an optional "wet" or "dry" split hemisphere wellhead (Figure 5).

- The Humble Exxon Subsea Production System (SPS) combines optional manned and unmanned operations. A track-mounted remotely controlled robot performs the unmanned maintenance tasks. One platform may be used to provide centralized control of several seafloor well clusters. Well clusters could be sealed in by plexiglass covers to trap seepage or spills (Figures 6, 7, and 8).

- Transworld -- a subsidiary of the Kerr-McGee Corporation – recently unveiled a "Total Concept" system for remote offshore development that uses a "dry" wellhead and a complex wellhead chamber and diving bell (Figures 9 and 10).

All of the subsea systems will require one platform or mooring buoy for each field developed.

Advantages of Subsea Systems

Subsea systems will become essential in the event a large shallow offshore petroleum deposit is discovered. As a rule, the lateral drift of slant wells directionally drilled from a platform is limited by the vertical well depth. Full development from one or two conventional platforms would be technically impossible, while the cost of additional platforms would be prohibitive. Subsea completions might also solve the problem of "unsightly production platforms" near resort areas and picturesque shorelines like Santa Barbara, California. Subsea completions also could minimize navigational problems in important shipping lanes. Other variations of subsea well completion techniques could be used in the development of Arctic offshore petroleum deposits. Where pack ice and ice flows scrape or scour the seafloor, raised wellheads would be destroyed. Therefore, some wellheads may have to be recessed beneath the seafloor (Figure 11).

Subsea Oilwell Completions

Figure 1. Standard Triple-Platform Completion

deep water operators will not be able to afford the convenience and luxury of multiple forms for field development Single, all-purpose structures must be designed to support field functions

Figure 2. Stacked Single Platform

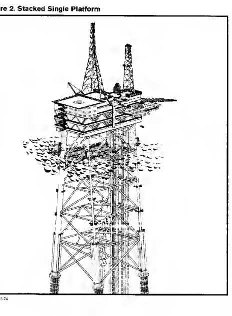
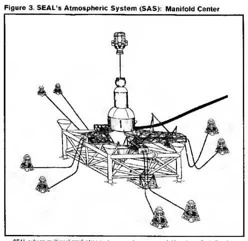


Figure 3. SEAL's Atmospheric System (SAS): Manifold Center



SEAL subsea multi-well production system operating as a manifold center collects flow from remote seafloor wells A similar system with two simulated wellheads is now being tested in the Gulf of Mexico

Figure 4. SEAL's Atmospheric System (SAS): Remote Well Clusters

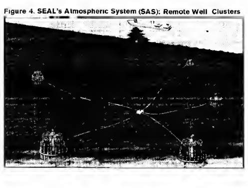


Figure 5. Lockheed's Wet-or-Dry Wellhead

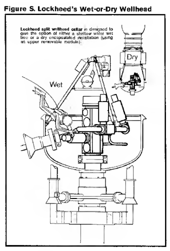


Figure 6. Humble's Main Platform

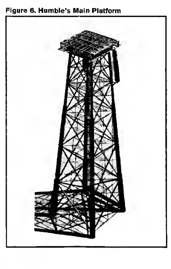
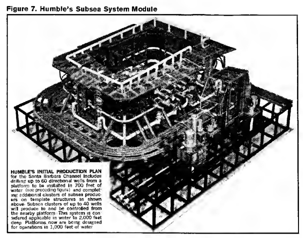
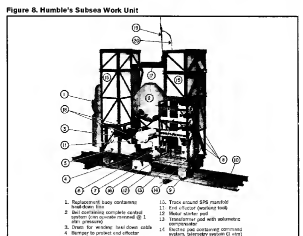


Figure 7. Humble's Subsea System Module



HUMBLE'S INITIAL PRODUCTION PLAN for the Santa Barbara Channel includes drilling up to 60 directional wells from a platform to be installed in 700 feet of water (see preceding figure) and completing additional clusters of subsea producers on template structures as shown above. Subsea clusters of up to 40 wells will produce to and be controlled from the nearby platform. This system is considered applicable in water to 2,000 feet deep. Platforms now are being designed for operations in 1,000 feet of water

Figure 8. Humble's Subsea Work Unit



1. Replacement buoy containing haul-down line
2. Bell containing complete control system (can operate manned @ 1 atm pressure)
3. Drum for winding haul down cable
4. Bumper to protect end effector on surface
5. Main hydraulic supply with compensator and motors
6. Orientation bushing
10. Track around SPS manifold
11. End effector (working tool)
12. Motor starter pod
13. Transformer pod with volumetric compensator
14. Electric pod containing command system, telemetry system (1 atm)
15. Foam for flotation
16. Replacement valves
17. Lifting beam

Figure 9. Transworld Diving Bell and Work Chamber

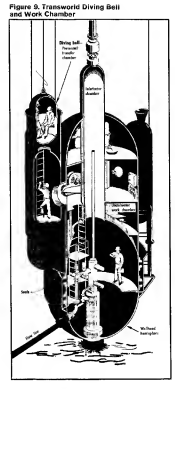


Figure 10. Transworld's "Total Concept" Production to Storage

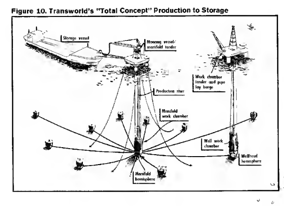
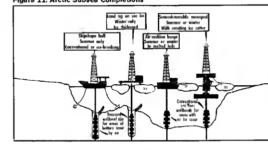


Figura 11. Arctic Subsea Completions



OIL AND GAS PIPELINE CONSTRUCTION

Introduction

Pipelines are an essential complement to the development of new petroleum deposits. They handle all overland movements of natural gas, most crude oil shipments to refineries and deepwater oil export terminals, and distribution of petroleum products from large refining complexes to major consuming centers. Initially developed in the late 19th century as an economical alternative to railroads, pipelines today provide the most efficient means of transport, rivaled only by long-distance shipping.

Pipeline Planning

The planning of large-diameter pipelines must take into account several factors, including long-term requirements for shipments of crude oil or natural gas.

- Detailed studies of oil and gas reserves are required to determine the availability of supply over a period of years. Reserve life must be adequate to amortize the pipeline project and to guarantee a reasonable return on capital investment.

- Physical and chemical characteristics of the oil or gas must be examined. Gravity, viscosity, and paraffin content affect oil pumping requirements and pipeline costs. Natural gas liquids, hydrates, and corrosive elements such as hydrogen sulfide and carbon dioxide have to be removed prior to shipment through a gas pipeline.

- Additional points of supply and offtake along the proposed pipeline must be considered to determine the best route and line capacity. Where feasible, the route selected will be the shortest distance to the receiving terminal to minimize the high cost of pipeline construction; about 80% of the investment is in the buried pipe. Standard pipeline construction costs in the United States in 1973 ranged from $20,000 per mile for a 4-inch line to about $260,000 per mile for a 42-inch line.

- Maps are scrutinized for general terrain conditions affecting accessibility, such as swamps, lakes, rivers, mountains, and cities. Preliminary field reconnaissance by airplane and jeep is followed by a detailed land survey. Surface elevations along the route are studied to determine the location and number of pumping stations and the hydraulic gradient.

- Right-of-way easements have to be obtained from all property owners along the route. Easement widths vary but are typically 50- to 60-foot strips.

Pipeline Diameter

Economies of scale in construction and operating costs can be realized with the use of "big inch" pipelines. Large-diameter pipelines are defined as those with outside diameters of 20 inches or more. The tabulation shows that a tripling in the diameter of small lines can result in an approximate fifteen- to twenty-fold increase in daily throughput.

Pipeline Diameter (Inches)	Average Pipeline Throughput (Thousand b/d)
8	17
12	38
16	100
20	140
24	240
28	340
32	500
36	750
42	1,000
48	2,000

Pipeline Construction

Pipelines are constructed in 100- to 150-mile sections, each with its own construction crew (called the "spread"). The length of the route will determine the number of contractors required to provide enough spreads of men and equipment for construction of the entire pipeline within a given time period. In good pipeline country, each crew should complete 1 to 3 miles of line per day, and the distance between the front and the back of the crew usually will not exceed 3 miles.

Clearing the Right-of-Way

After company engineers stake the pipeline route, gaps are cut in fences to provide access for the right-of-way gang that clears the route of obstructions. Ravines and draws are filled in, and small humps and hills are leveled with bulldozers and graders. Frequently a road is constructed along the ditch line to permit passage of other heavy equipment.

Ditching

The next piece of equipment to follow along the right-of-way is the ditching machine. The width of the ditch is usually twice the pipe diameter, and the depth must permit 2 to 3 feet of cover with the pipe in the ground. Where rock is encountered, the ditch must be drilled and blasted. The ditch sometimes is cut through a roadway; embankments under railroads and pavement usually are bored with augers and then cased off.

Pipe Stringing

All linepipe is first delivered to centrally located storage yards where it may be coated and wrapped with anti-corrosive materials (Figures 1a and 1b). Stringing

of the pipeline along the ditch is done by trucks pulling special pole-type trailers. Pipe stringing is carried out along the right-of-way in both directions from the storage yard, to minimize hauling. The pipe is offloaded from the trailers with a tractor-mounted sideboom hoist (Figure 2).

Pipe Bending

It is necessary to cold-bend certain sections of pipe so that the finished line will conform to the slope of the ground as nearly as possible. The bends must accurately reflect the angle required at each point along the route (Figure 3).

Pipe Alignment, Joining, and Welding

The lineup crew then aligns the various pipe sections and welds them together with a temporary stringer bead (Figures 4a, 4b, and 4c). This crew usually leaves behind a continuous line supported by skids alongside the ditch (Figure 4d). The welding crew follows, completing the welding of each joint by applying two or more continuous beads. Submerged arc butt welding is the most vital craft of all in the construction process (Figure 4e). If a weld fails to pass X-ray inspection, or should the inspector believe any weld to be faulty, it must be cut out and replaced.

A tie-in crew completes the welding, joining all sections to make a continuous welded tube. All remaining exposed pipe joints and valves, as well as damaged pipe areas that rested on skids, are coated and wrapped after welding is completed.

Pipe Laying and Burial

The lowering-in-crew places the finished pipeline into the ditch, usually with a sideboom tractor pipèlayer (Figure 5). The pipe is lowered into the trench by a series of slack-loops. The distance between loops varies with the pipe size, the terrain, temperature, and other factors that might damage the pipe.

As the pipe is laid in the trench, certain portions are tied in position with earth until the backfilling crew arrives to completely bury the line. Backfilling usually is done with special tractors; bulldozers or draglines also can be used. Before the final crown of dirt is placed on the ditch, one tread of a heavy tractor is run over the fill to compact it. Burial of the pipeline is complete when this surface fill is leveled and smoothed.

Cleanup

The last crew in the spread removes all pipe skids, waste, and refuse from the right-of-way. This cleanup crew also levels the terrain, erects diversion dikes, drainage ditches, or levees where needed, and replaces previously cut fences.

Testing

Pipeline testing is done hydraulically. Water from a convenient source is pumped into the line with portable units at one end. A specially designed scraper is inserted ahead of the water and pumped through the line to remove all dirt, scale, and refuse. The pipeline then is given a 24-hour pressure test for leaks. After the automatic controls and monitoring devices are installed and checked out, the pipeline is completed.

Offshore Pipelines

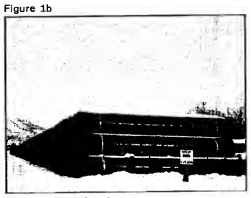
Construction of offshore pipelines is considerably more complex than onshore operations. Tractors are replaced with floating, self-contained barges that perform all of the construction operations at one point (Figure 6). Anchoring and securing the line to the sea bottom is performed with draglines. Cement coatings and concrete weights may be used to hold the pipe to the seafloor. Weather and water conditions frequently halt construction for many days at a time.

Oil and Gas Pipeline Construction

Figure 1a

Pipe Yard at a Port

Figure 1b



Pipe Yard Inland

Figure 2

Pipe Stringing and Offloading along Right-of-Way

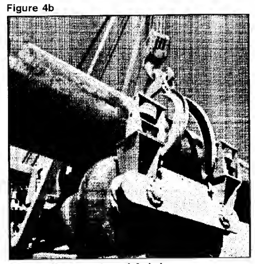
Figure 3

Pipe Bending Machine

Figure 4a

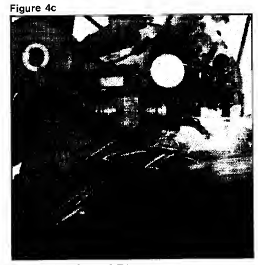
Pipe Alignment, Joining, and Welding Operations

Figure 4b



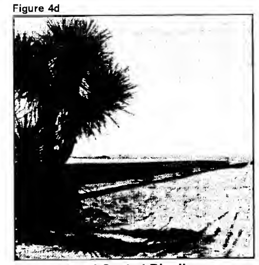
Pipe Alignment and Joining

Figure 4c



Tack Welding of Pipe

Figure 4d



Wrapped and Coated Pipeline

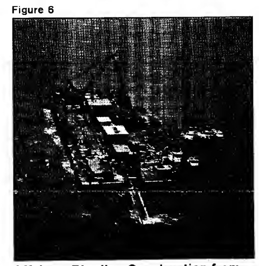
Figure 4e

Final Pipeline Arc Welding Operations

Figure 5

Pipeline Being Laid

Figure 6



Offshore Pipeline Construction from a Barge

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PETROLEUM STORAGE INSTALLATIONS

Introduction

Petroleum production, transportation, processing, and marketing require large amounts of storage capacity to avoid interruptions in supply. Crude oil, natural gas, and petroleum products can be stored (1) above the ground in wood or steel tanks; (2) below the ground in depleted petroleum reservoirs, abandoned mines, or excavated rock or salt caverns; and (3) offshore in concrete or steel containers. The location and purpose of the storage unit determine the type of installation and the choice of construction materials.

Above-Ground Installations

Oil fields, pipeline facilities, tanker terminals, and refineries require above-ground storage. Storage sites vary in size from 1,500-barrel wood and steel tanks at producing wells (Figure 1) to large tanks (Figure 2), tank batteries (Figure 3), and tank farms (Figure 4). The farms may include as many as 200 tanks – each with a capacity of nearly 1 million barrels. Such tank farms require 20 to 30 acres of land for each million barrels of storage capacity. The floor area of one 800,000-barrel tank is roughly equivalent to the area of a football field. Storage sites for product distribution systems are smaller and are located near railroad spurs, highways, ports and waterways, or pipelines. Crude oil and product tanks are normally cylindrical, while tanks for pressurized storage of liquefied petroleum gases such as butane and propane are spherical (Figure 5).

Underground Installations

Natural gas, liquefied petroleum gas, and petroleum products are sometimes stored underground. Crude oil – although not yet stored underground in the United States – has been successfully kept in abandoned mines in South Africa since 1969. In Europe, more than 100 million barrels of underground crude storage capacity is in use, under construction, or planned. Natural gas is kept in many depleted oil reservoirs throughout the world.

The potential for additional underground storage is great. The United States has more than 200 large salt domes along the Texas-Louisiana coast that could be used for this purpose (Figure 6). The total potential storage capacity of these domes is estimated at about 650 million barrels. Thick saltbeds can also be used for storage. Cavities can be created in salt masses at moderate cost by circulating water down through the tubing of a single well and forcing the brine solution

up through the casing (Figure 7, a, b, and c). More costly storage in rock caverns can be obtained through conventional room and pillar mining (Figure 8). Such manmade caverns are now being used for propane storage in the eastern United States. Abandoned mines and depleted oil and gas fields (Figure 9) provide other storage options.

The operation of all underground storage installations, whether in mines, caverns, or depleted oil reservoirs, is based on the displacement of water and brine by oil, gas, or refined products. The storage area is filled by pumping petroleum down through the well casing and forcing water or brine to the surface through the tubing. By reversing the process, the stored petroleum is brought back to the surface when it is needed. In salt caverns, opening of the cavity can proceed simultaneously with storage operations. The storage area gradually expands if fresh water is used instead of a saturated brine solution. Brine solutions may be recycled from a surge tank at the surface to reduce fresh water requirements and eliminate saltwater disposal problems, once the desired cavern size is obtained. Costs for salt dome oil storage are estimated at $0.75-$1.00 per barrel of storage capacity, compared with $5.00-$7.00 for steel tank storage. The latter range does not include the cost of pilings sometimes needed beneath large tanks.

Offshore Installations

Growing offshore oil production in remote deepwater locations has led to the use of steel and concrete underwater storage structures. Submerged steel bell-shaped tanks (Figure 10, a and b), floating steel buoys (Figure 11), and "Condeep" concrete silo-type production platforms (Figure 12, a and b) are a few of the more novel departures from conventional platforms and tanks. Concrete silo structures cost about half as much as steel production platforms and provide storage capacity at no extra cost.

"Condeep" platforms may dominate development of the North Sea, where water depths range from 200 to 600 feet and 90-foot waves have been reported. Phillips, Mobil, and Shell-Esso have ordered four "Condeep" platforms measuring 600 feet to 738 feet high, with base diameters of 330 feet. Oil storage capacity amounts to 900,000 to 1,000,000 barrels for each platform. Phillips recently installed the first "Condeep" platform at the Ekofisk field in 230 feet of water, at a cost of almost $30 million. This compares with a cost of about $200 million for a steel platform with much less storage capacity.

Above-Ground Storage

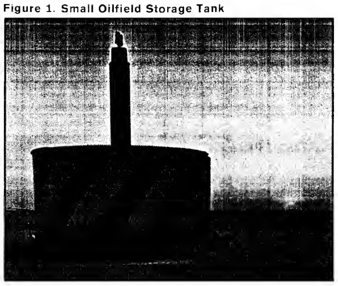
Figure 1. Small Oilfield Storage Tank

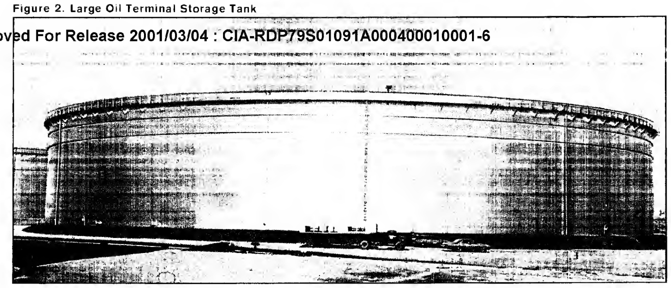
Figure 2. Large Oil Terminal Storage Tank

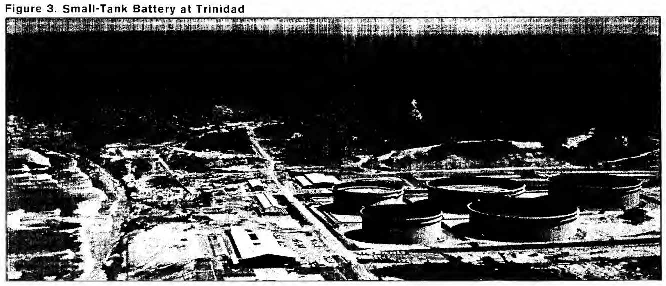
Figure 3. Small-Tank Battery at Trinidad


Large-Tank Farm at Kharg Island, Iran


Figure 5.
Pressurized Spherical Gas Storage Tank

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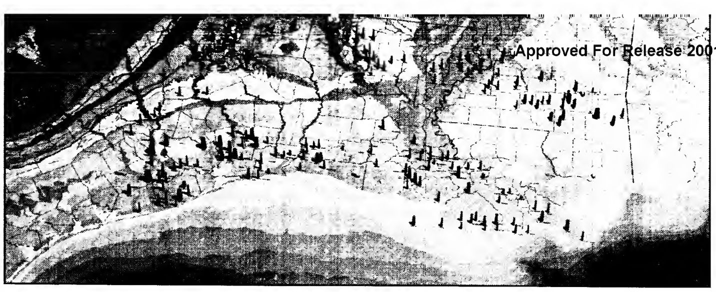


Figure 7a. Salt Dome Storage Cavern

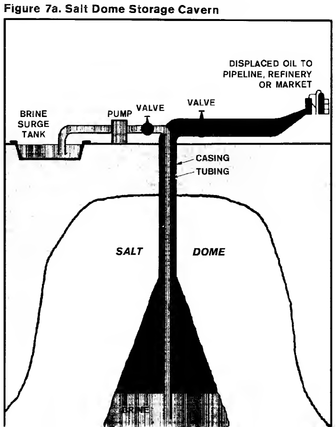
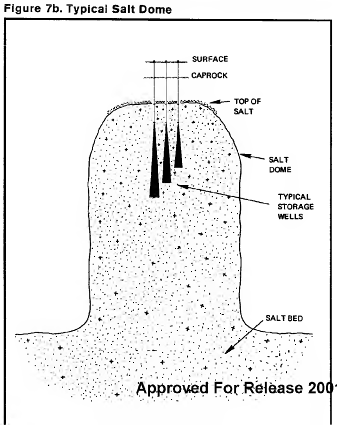


Figure 7b. Typical Salt Dome



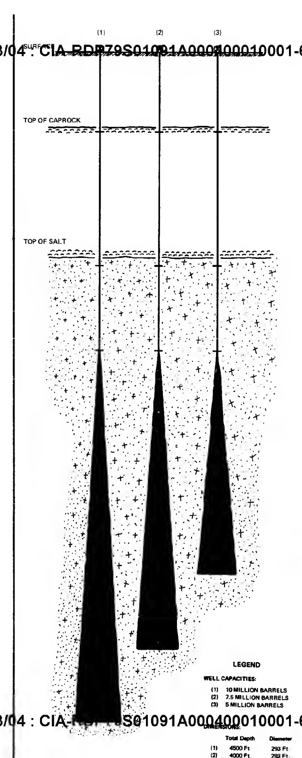


Figure 8. Storage in Excavated Rock Caverns and Abandoned Mines

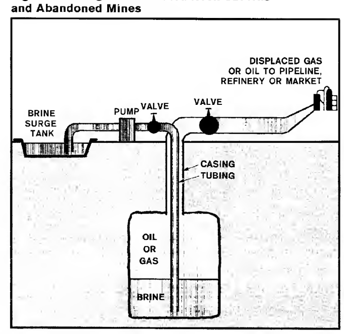
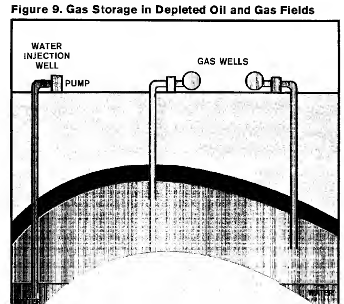
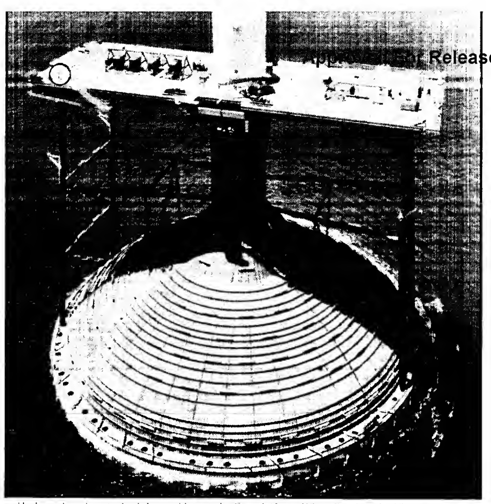


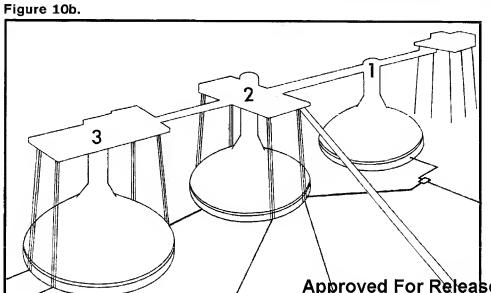
Figure 9. Gas Storage in Depleted Oil and Gas Fields





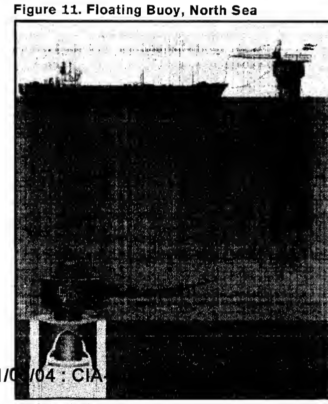
Underwater storage tank topped by production platform. When floating, the Khazzan Tank No. 2 is higher than a 20-story building with a base of almost 300 feet. For an impression of size, note the person circled on the production platform floor. Each tank stores 500,000 barrels of oil and costs almost $9 million.

Figure 10b.

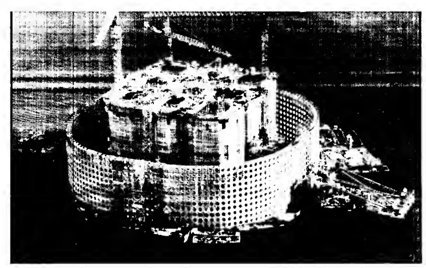


The largest underwater oil storage complex in the world is in Fateh field, Persian Gulf, off the

Figure 11. Floating Buoy, North Sea

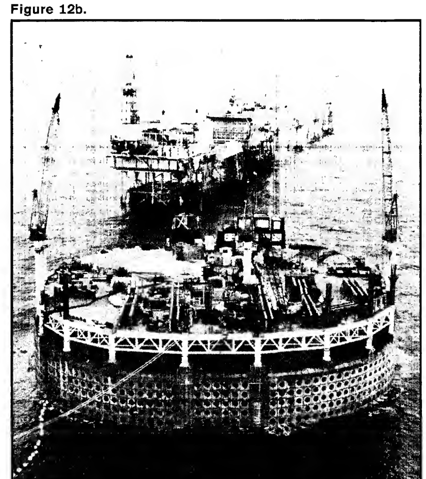


This floating buoy tank will store 300,000 barrels of crude oil



First "Condeep" under construction near Stravanger, Norway for Phillips Petroleum Company's Ekofisk field.

Figure 12b.



In the heart of Ekofisk Center is the world's largest offshore oil storage tank, fore-

DEEPWATER OIL TERMINALS

Introduction

The advent of the very large crude carrier (VLCC) has made most of the world's oil ports obsolete. Supertankers ranging from 175,000 to 500,000 deadweight tons (DWT) now constitute about 45% of world tanker capacity. Few ports can accommodate these tankers, which have drafts ranging from 55 to 90 feet. Only about 30 ports capable of unloading the giant ships are presently in use or are under construction. Vast tonnages are delivered to deepwater terminals such as Rotterdam, Bantry Bay (in Ireland), Genoa, and Yokohama—all of which are key refining and distribution points in the world oil trade. US ports cannot handle ships of more than 100,000 DWT unless part of their cargo is offloaded into smaller ships in deep water.

Supertankers are expected to account for nearly 60% of the world oil fleet capacity by the end of 1978 because they offer savings in transport costs per barrel of up to 50%, compared with small ships. The need to develop deepwater oil terminals will increase accordingly.

Planning a Deepwater Terminal

The materials and equipment needed to build deepwater terminals are fairly easy to obtain, and manpower and contractors capable of doing the job are available in most cases. The biggest obstacles are political, economic, and environmental issues such as long-range oil import policy, jurisdictional disputes between different units of government, conflicting commercial interests, and the threat of pollution.

Comprehensive planning is necessary to assure the successful operation of deepwater terminals. Preliminary studies must consider the precise location and type of facility best suited to serve a refining complex. These studies must take into account the arrival patterns of ships, types and sizes of cargoes, storage tank requirements for different grades of oil, weather and tide conditions, and shipping channels, as well as the environmental impact.

Siting a Terminal

The first planning problem is fitting the terminal's capabilities to the needs of the refineries being served. Allowance should be made for future expansion of refining operations, if appropriate. Data must be gathered on wind, wave heights, currents, tidal movements, water depths, sea-bottom topography, and soil conditions. Provision must be made for tanker approach lanes plus maneuvering and anchoring areas. Land must be available for storage tanks. The area should be able to provide tankers with fresh water, stores, and fuel oil bunkers.

Types of Terminals

Deepwater oil ports can be developed in several ways.

Dredging Existing Channels

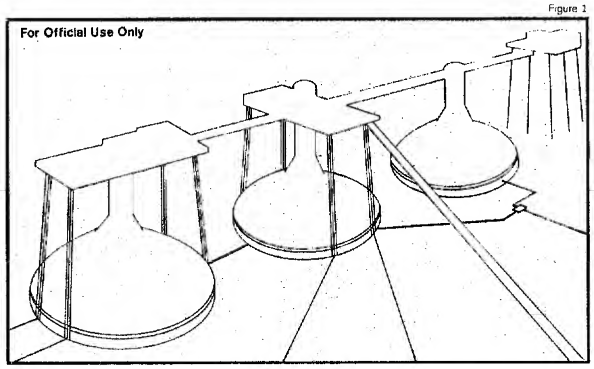
Dredging a new deepwater harbor like Rotterdam's Europort is economic only where several large industrial installations are being served. In many cases, dredging costs for deepening existing ports are prohibitive.

Sea Islands

These structures consist of a fixed offshore berth and platform with unloading facilities connected to shore by submarine pipes. Sea island terminals are restricted to fairly sheltered locations. Tanker supply services may be difficult to arrange at sea islands (see Figure 1).

Figure 1

For Official Use Only



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Sea Island

Multibuoy Mooring

The ship is moored in a fixed position between a number of anchored buoys. Cargo is discharged through floating hoses and a submarine pipeline to shore. This type of berth, like sea islands, is restricted to sheltered areas. Ship supply services also pose a problem.

Fixed Berth or Finger Pier

The simplest and best terminal installation is the finger pier built out into deepwater. Its use is restricted by cost considerations to adequately sheltered areas where deep water lies close to shore. Given this kind of site, the finger pier provides the best arrangement in terms of safety and ship supply services. Moreover, its closeness to shore often means a shorter pipeline network than for alternative systems (see Figure 2).

Figure 2

Fixed Berth or Finger Pier Unloading System

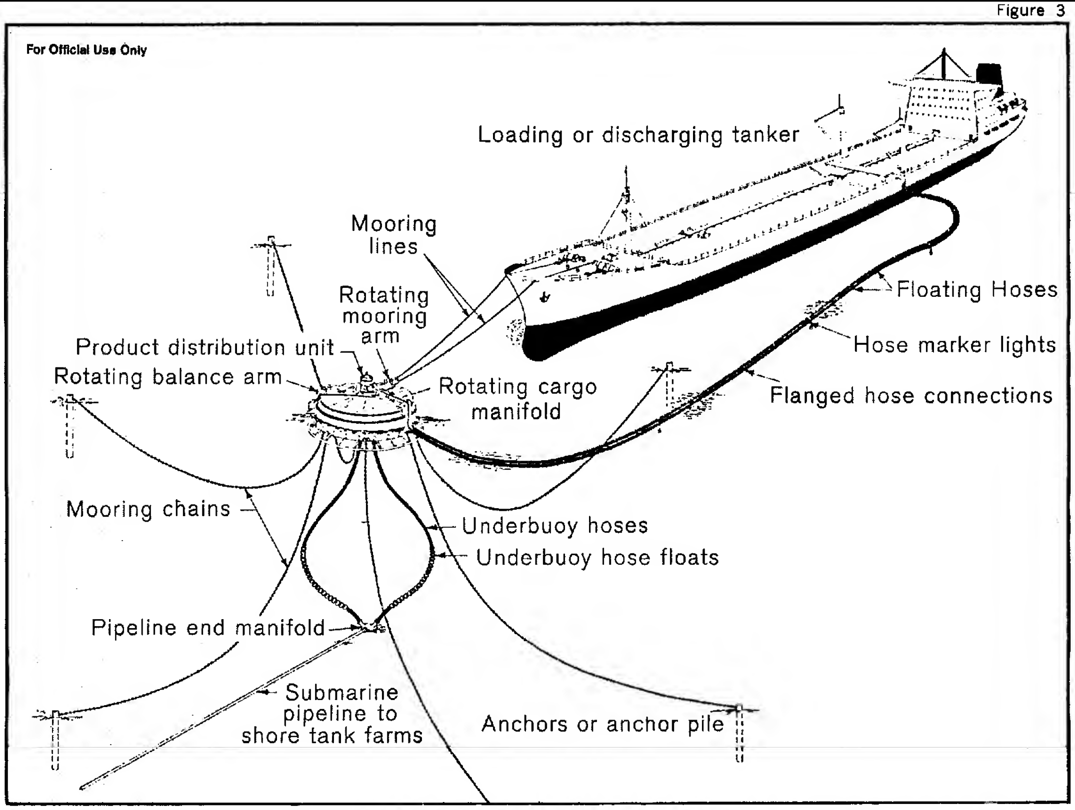
Single Point Mooring (Single Buoy Mooring) Systems

A single point mooring system, under which the ship has free heading, sometimes must be employed in preference to multibuoy fixed-heading mooring. For instance, a 100,000-DWT ship is the maximum size of tanker that can reasonably be handled by fixed-heading mooring buoys in areas open to fairly severe sea conditions. For larger tankers the chance of collision and the strain on mooring lines must be reduced by allowing the ship to swing freely in the prevailing wind, current, and wave conditions; an anchored buoy with a rotating top thus would be preferable to a fixed tower. Monobuoys are generally used where berthage has to be provided outside of a harbor or natural shelter. Several operating problems are associated with monobuoys: the floating discharge hoses are vulnerable to damage and oil spills; hoses are limited to low discharge rates, and ship supply services are difficult to provide (see Figure 3).

Tanker Loading and Unloading

The larger oil tankers are capable of an improved oil discharge rate which reduces the time spent in berth. Ideally, operators of tankers aim at hourly discharge rates of about 10% of the vessel's carrying capacity. However, physical problems prevent supertankers from achieving this target; the longest VLCCs may realize only half this rate. Loading and discharge rates are limited by the ships pump capacity and the pressures that the loading hoses and ship's pipework can withstand. The maximum pressure in these systems is about 200 pounds per square inch.

Figure 3



Single Point Mooring System

Comparisons of Selected Crude Oil Tankers

Capacity (Deadweight Tons)	Length (Feet)	Draft (Feet)	Maximum Oil Discharge Rates (Tons per Hour)
16,000	522	28	1,500
32,000	650	35	3,000
50,000	735	40	4,000
75,000	820	43	6,000
106,000	930	50	9,000
217,000	1,075	63	12,000 - 15,000
250,000	1,100	70	14,000 - 16,000
326,000	1,135	81	15,000 - 18,000
500,000 (Planned)	1,300	90	N.A.

THE PROPERTIES OF CRUDE OIL

General Characteristics

Crude oils are complex mixtures of hydrocarbons plus minor amounts of sulfur, nitrogen, oxygen, and metals. Their characteristics vary widely from one oilfield to another and even from one well to another in the same oilfield.

Crude oils range in character from light, flowing, reddish-brown liquids with a large proportion of easily distillable fractions to highly viscous, semi-solid, black substances with little distillable material. Crude oils generally are flammable. The odor of crude ranges from pleasantly aromatic for some light types to the highly unpleasant garlic smell usually associated with high-sulfur oils.

In spite of wide differences in physical aspects, the elements present in different crude oils vary within narrow limits, as shown below:

	Percent of Total Weight
Carbon	84-87
Hydrogen	10-14
Sulfur	0.06-7
Nitrogen	0.1-1.7
Oxygen	0.5-1.5
Metals (iron, vanadium, nickel, etc.)	0.03

Types of Crudes

Crude oils are commonly classified according to the residue from their distillation. The following three classifications comprise about 85% of all crude oils:

- ***Paraffin-Base crudes*** are good sources of high-quality lubricating oils and kerosene as well as wax. They usually have low contents of sulfur, nitrogen, and oxygen.
- ***Asphalt-Base crudes*** are good sources of high-quality gasoline and special lubricating oils as well as asphalt.
- ***Mixed-Base crudes*** contain considerable amounts of both wax and asphalt. Practically all products can be obtained from them, at lower yields than from the other two types.

Testing Procedures

Knowledge of the characteristics of individual crude oils is essential to achieving maximum efficiency in refining. Comprehensive analytical methods are employed to determine the important characteristics of the crude. These characteristics include:

1. Specific gravity – ratio of the weight of a unit volume of oil to the weight of the same volume of water at a standard temperature

2. Sulfur content

3. Nitrogen content

4. Color

5. Viscosity -- a measure of the oil's resistance to flow.

6. Pour point – the lowest temperature at which the oil will pour or flow.

7. Fractional composition -- the array of petroleum products recovered by vaporizing the crude and collecting the fractions that condense at different temperatures.

REFINING OF OIL

General Description of Refinery Operations

A modern petroleum refinery consists of a number of processing units designed for physical and chemical conversion of crude oil into useful petroleum products (see simplified flow diagram). Because refineries process different types of crude oil and produce different assortments of products, no two refineries are exactly alike. Most modern refineries, however, employ the same basic processes and make use of the same basic types of equipment. The product mix of a refinery can vary substantially, with little or no change in equipment. Refineries in the United States, for example, are geared to maximize output of high-octane gasoline; the same units can be operated to maximize output of other products, such as diesel fuel or fuel oil.

Distillation

The first and fundamental step in refining is distillation, which is the rough separation of the crude oil molecules according to their size and weight. ***Primary distillation*** takes place in towers as high as 100 feet which contain perforated trays set one above the other at different levels. These are known as fractionating towers because they separate crude oil into different fractions or parts. Crude oil is heated to about 700° F and is pumped in vaporized form into the fractionating units. As the vapors rise, they become cooler, condense at differing rates, and are collected in different levels of trays and piped to other parts of the refinery.

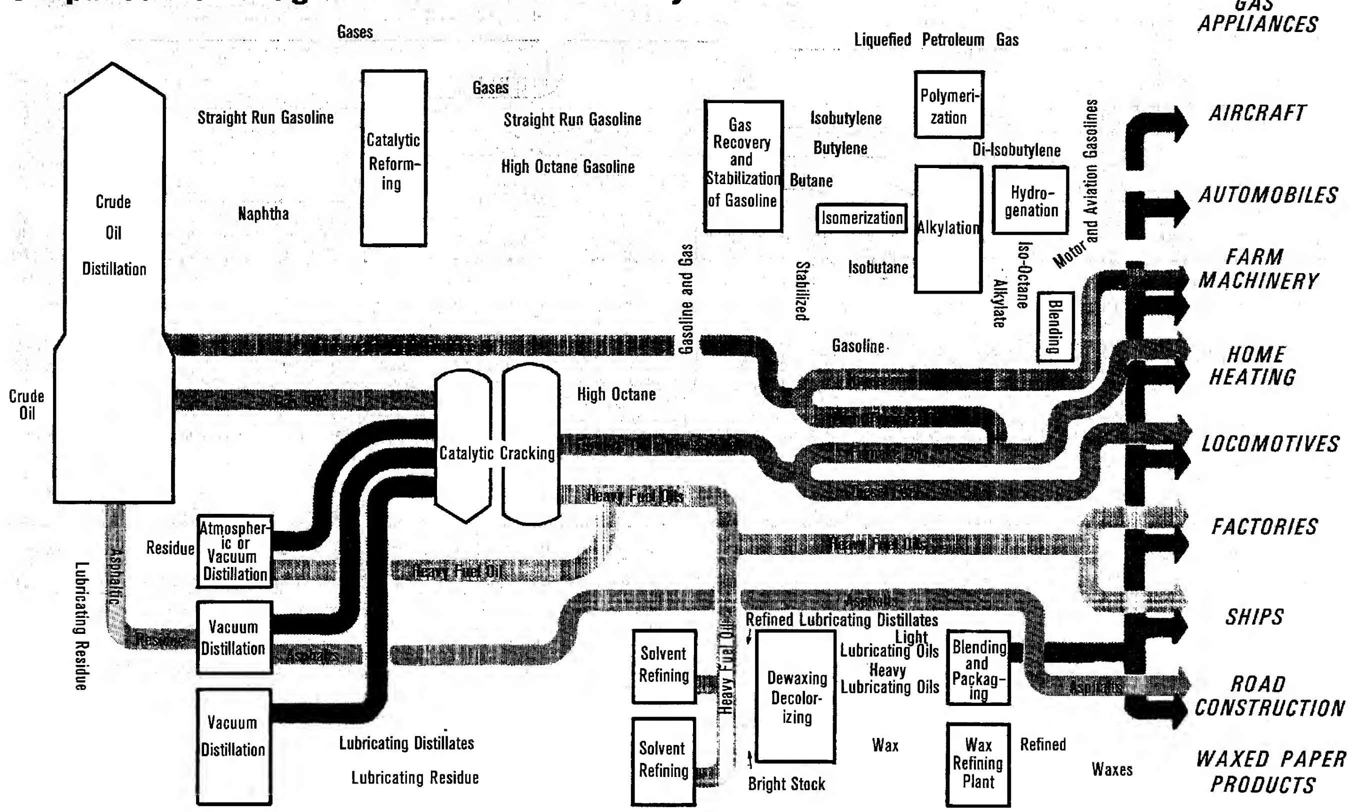
Gasoline condenses at the lowest temperature, near the top of the tower. Other distillates, including kerosine, jet fuel, diesel fuel, and light heating oils condense at higher temperatures. Gas oil, which is coverted by more sophisticated processes into gasoline or fuel oil, condenses at even higher temperatures. The heaviest fraction, which condenses at the highest temperatures, is known as residuum. In many refineries ***vacuum distillation***, a two-step process using two distillation towers, is used to further condense the residuum to obtain heavy fuel oil, lubricating oil, grease, asphalt, or wax.

Distillation can separate crude oil into its fractions, but it cannot get more out of a particular fraction than nature put there. The demand for different products does not necessarily conform with the proportions found in the crude oil. Refineries are able to produce more gasoline and other high-quality fuels than can be obtained in the distillation process by using a number of secondary processes.

Secondary Processes

The most common secondary process is cracking – the breaking of large molecules into smaller ones. The oldest process in use is ***thermal cracking***, which relies on heat alone to convert heavy, lower quality fractions into lighter,

Simplified Flow Diagram of a Modern Refinery



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high-quality stocks. Few thermal crackers have been built during the past decade, and today the process is used primarily to prepare feedstocks for catalytic cracking.

In the ***catalytic cracking*** process, oil vapors heated to about 1,000° F are passed over a silica-alumina catalyst, which causes the heavier oil fractions to crack into lighter ones (gasoline and distillate fuels); these lighter fractions are then sent to a fractionating tower for distillation. The used catalyst goes to a regenerator where it is activated for further use by the burning off of the carbon (coke) deposited on the catalyst in the cracking process.

Hydrocracking is a more recently developed process used to convert residual stocks into high-quality products. It employs a series of high pressure reactors to mix hydrogen with oil vapors at temperatures up to 1,100° F. The process combines the use of a silica-alumina cracking catalyst with platinum or nickel as the hydrogenating agent and obtains high yields of good-quality distillates.

Other key processes found in most refineries include:

Catalytic Reforming – a continuous process, which uses platinum or platinum and rhodium on alumina as a catalyst to rearrange molecules, upgrading low-octane naphthas into high-octane gasolines or producing aromatics – benzenes, toluenes, xylenes -- for petrochemical use.

Alkylation -- a process for combining smaller dissimilar molecules into larger ones in the presence of sulfuric acid or hydrofluoric acid to provide high-octane components for premium motor gasoline or aviation gasoline.

Polymerization -- a process for combining similar molecules in the presence of phosphoric acid to yield high-octane gasolines and petrochemical materials. The process is gradually being replaced by alkylation.

Isomerization – a process in which the atoms within a molecule are rearranged without changing the total number. It is used in many refineries to produce high-octane gasoline components.

Coking – a thermal cracking process in which a heavy feedstock is heated to about 900°-1,000° F under moderate pressure to produce a high-quality gas oil suitable for use in catalytic cracking. Gas, gasoline, and coke are produced as secondary products. The coke is used as industrial fuel or, when purified, is valuable for production of electrodes for the aluminum industry.

Gas Recovery -- the collection of refinery gases and their separation by use of multiple fractionating towers. The gases are used in production of gasoline and petrochemicals.

Hydrogen Treating (hydrodesulfurization) – a series of processes using cobalt-molybdenum catalysts on a wide variety of petroleum stocks to improve the quality of final products by removing sulfur.

Blending

The final step in producing gasoline and fuel oils is blending. It involves mixing two or more fractions having different properties to obtain a final fuel with the desired specifications. This can be done "off-line" in blending tanks or "on-line" in a refinery's pipelines.

PETROCHEMICALS

A widely accepted definition of petrochemicals is: "Chemical compounds or elements recovered from oil or natural gas, or derived in whole or in part from oil or natural gas hydrocarbons, and intended for chemical markets."

How and Where Petrochemicals Are Produced

Since petroleum is essentially a mixture of hydrocarbons (carbon and hydrogen), the chemicals made from it are nearly all organic chemicals. In theory, virtually any organic chemical can be made from petroleum. In practice, the range is wide but not unlimited. In many cases, the same compound can be made from more than one hydrocarbon raw material. The raw materials chosen will depend on what is economically available and the product mix needed.

Basic raw materials for petrochemical manufacture are natural gas, refinery gases, and liquid hydrocarbon fractions. A larger number of secondary raw materials are derived from these basic materials and form the building blocks of the industry. These include acetylene, paraffins (methane, ethane, propane, and butane), and olefins (ethylene, propylene, and butylene). Propane enjoys the largest use as a hydrocarbon raw material.

Almost 90% of the world's organic chemicals are derived from petroleum hydrocarbons; this share may rise to 97%-98% by the end of the century. Nevertheless, in the United States the entire output of petrochemicals consumes less than 6% of all petroleum refined.

Petrochemical manufacture commonly requires the application of petroleum processing techniques to the production of finished chemical products. Petrochemical units are usually continuous, elaborate, and highly automated and operate with catalysts. They require a large scale of operation to be economically feasible. In recent years, the sizes of petrochemical plants have risen sharply. For example, a typical ethylene plant in the early 1960s had a capacity of about 70,000 tons per year; at present the capacity of such plants normally approximates 400,000 tons annually.

All petrochemical installations must have ready access to the various refinery fractions used as raw materials. They therefore are placed as close as possible to an oil refinery.

Petrochemical Groups and Types

There are three groups of petrochemicals, depending on chemical composition and structure:

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(1) *Aliphatic* -- Organic compounds having an open chain of carbon atoms, normal or branched, saturated or unsaturated. This group includes acetic acid, acetic anhydride, acetone, butadiene, ethyl alcohol, ethyl chloride, ethylene glycol, formaldehyde, ethyl alcohol, and isopropyl alcohol. Most of these petrochemicals are made from methane, ethane, propane, and butane.

(2) *Aromatic* -- Organic compounds containing or derived from the basic benzene ring, which has six carbon atoms. This group includes benzene, toluene, xylene, and their derivatives.

(3) *Inorganic* -- Compounds not containing carbon atoms. This group includes sulfur, ammonia, nitric acid, ammonium nitrate, and ammonium sulfate.

Aliphatic compounds account for about 60% of all petrochemicals produced and are also the largest group in value terms. Aromatic compounds are smallest in volume, constituting about 16% of the total, but are more important in value than inorganic petrochemicals.

The number of individual petrochemicals runs into the thousands. They are, for the most part, grouped according to type and general use, as follows:

(1) Plastics and resins -- molded, extruded, and machined articles and materials used in the home and industry; paints and surface coatings; films and packaging materials.

(2) Synthetic fibers -- clothing, floor coverings, decorative textiles, tire cords, ropes.

(3) Synthetic rubber.

(4) Materials for agriculture -- fertilizers, insecticides, cattle feed improvers.

(5) Detergents.

CONVERSION FACTORS

1. Approximate Conversion Factors for Crude Oil*

FROM \ INTO (MULTIPLY BY)	Metric Tons	Long Tons	Short Tons	Barrels	Kiloliters (Cubic Meters)	1,000 Gallons (Imp.)	1,000 Gallons (US)
Metric Tons	1	0.984	1.102	7.33	1.16	0.256	0.308
Long Tons	1.016	1	1.120	7.45	1.18	0.261	0.313
Short Tons	0.907	0.893	1	6.65	1.05	0.233	0.279
Barrels	0.136	0.134	0.150	1	0.159	0.035	0.042
Kiloliters (cub. meters)	0.863	0.849	0.951	6.29	1	0.220	0.264
1,000 Gallons (Imp.)	3.91	3.83	4.29	28.6	4.55	1	1.201
1,000 Gallons (U.S.)	3.25	3.19	3.58	23.8	3.79	0.833	1

*Based on world average gravity (excluding natural gas liquids).

2. Approximate Conversion Factors for Petroleum Products

	FROM			
	Barrels to Metric Tons	Metric Tons to Barrels	Barrels per Day to Tons per Year	Tons per Year to Barrels per Day
	MULTIPLY BY			
Motor Gasoline	0.118	8.45	43.2	0.0232
Kerosine	0.128	7.80	46.8	0.0214
Gas Diesel	0.133	7.50	48.7	0.0205
Fuel Oil	0.149	6.70	54.5	0.0184

3. Volumetric Measures

FROM \ INTO (MULTIPLY BY)	Cubic Meters	Cubic Feet	US Gallons	Imperial Gallons	Liters	US Barrels
Cubic meter	1.0	35.31	264.15	219.95	999.97	6.285
Cubic foot	0.02832	1.0	7.481	6.229	28.32	0.178
US gallon	0.00379	0.1337	1.0	0.8327	3.785	0.0238
Imperial gallon	0.00453	0.160	1.201	1.0	4.546	0.0286
Liter	0.001	0.0353	0.2641	0.2200	1.0	0.006293
US barrel	0.1590	5.615	42.0	35.0	158.9	1.0

4. Miscellaneous:

Units of weight:

Short ton	2,000 pounds
Long ton	2,240 pounds
Metric ton	2,205 pounds

Units of volume:

Measurement ton (ship ton)	40 cubic feet
Register ton	100 cubic feet

Representative conversion factors:

Country	Barrels per Metric Ton
Abu Dhabi	7.493
Algeria	7.713
Angola	7.223
Bahrain	7.335
Congo	7.508
Gabon	7.245
Iran	7.370
Iraq	7.541
Israel	7.286
Kuwait	7.261
Libya	7.615
Morocco	7.602
Nigeria	7.508
Qatar	7.719
Saudi Arabia	7.428
Saudi Kuwait Neutral Zone	6.849
Turkey	6.400
United Arab Republic	6.901

5. **Rules of Thumb:**

a) Conversion between barrels per day and tons per year:
Barrels per day × 50 = tons per year.
Tons per year ÷ 50 = barrels per day.

b) Volumetric contents of pipelines:
(Diameter in inches)^2 = barrels per 1,000 feet.
Example: 30-inch diameter pipeline would contain approximately 4,752 barrels per mile.

6. Approximate Energy Equivalents (Conversions)

	Energy Content[1]	Coal Equivalent	Oil Equivalent[2]
1 million tons hard coal	7	1.0[3]	0.7
1 million tons coke	6.7	0.96	0.67
1 million tons lignite	2	0.29	0.2
1 million tons liquid fuels	10	1.43	1.0
1,000 million cubic meters natural gas	9	1.33	0.9
1,000 million cubic meters manufactured gas	4.2	0.6	0.42
1,000 KWH electricity	0.88	0.125	0.088

[1] One trillion kcal.
[2] One thousand barrels of oil per day equals approximately 2 trillion BTUs per year.
[3] Standard fuel—theoretical unit of energy, equivalent to 7,000 kcal per kilogram.